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REALISING THE OIL SUPPLY POTENTIAL OF THE CIS: THE IMPACT OF INSTITUTIONS AND POLICIES

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By Rudiger Ahrend and William Tompson

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Abstract

Realising the Oil Supply Potential of the CIS: The Impact of Institutions and Policies

This paper provides an overview of the political economy of oil in the CIS. It briefly situates the region's oil sector potential in the global context, before analysing the structural features of the oil sectors by country. It examines the ways in which CIS oil industries have been organised and governed since 1991, as well as questions of transport infrastructure and export routes, which are especially critical for Central Asia's landlocked producers. The paper finally considers the causes and likely consequences of the recent shift towards greater state ownership and control in Russia and Kazakhstan, the region's most important oil producers. The paper's central argument is that these changes have increased the risk that the full hydrocarbon potential of the CIS may not be developed in a timely and economically efficient way.

JEL Classification: L71, O57, P28, Q41

Keywords: CIS; Russia; Kazakhstan; Azerbaijan; Uzbekistan; Turkmenistan; Caspian; energy; oil; pipelines; political economy; growth; corruption; state ownership; pipelines; privatisation; property rights

Résumé

Réaliser le potentiel pétrolier des pays de la CEI : l'impact des institutions et des politiques publiques

Cette étude présente un panorama de l'économie politique du secteur pétrolier dans les pays de la CEI. Après une brève description du potentiel de la région, vu dans un contexte global, une analyse des caractéristiques structurelles des secteurs pétroliers pays par pays est présentée. L'étude propose également un examen des modes d'organisation et de gestion des industries pétrolières depuis 1991, ainsi que des questions d'infrastructure de transport et des routes de transit pour l'exportation, qui sont particulièrement cruciales pour les producteurs enclavés d'Asie Centrale. Enfin, les causes et les conséquences probables du mouvement récent vers un contrôle croissant du secteur par l'état en Russie et au Kazakhstan, les deux plus importants producteurs de la région, sont analysées. La conclusion principale de l'étude est que ces changements ont accru le risque que le plein potentiel des pays de la CEI ne soit pas développé de manière opportune et économiquement efficiente.

JEL Classification: L71, O57, P28, Q41

Mots-clés : CEI ; Russie ; Kazakhstan ; Azerbaïdjan ; Ouzbékistan ; Turkménistan ; Caspienne ; énergie ; pétrole ; oléoducs ; économie politique ; croissance ; corruption ; entreprises d'état ; privatisation ; droits de propriété

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REALISING THE OIL SUPPLY POTENTIAL OF THE CIS THE IMPACT OF INSTITUTIONS AND POLICIES

Rudiger Ahrend and William Tompson¹

The expansion of the state's share of the oil sector will constrain the development of this sector of the economy.

–Alekssei Kudrin, Minister of Finance of the Russian Federation²

1. Introduction

1. During 1998–2004, the Commonwealth of Independent States (CIS) accounted for 60% of incremental global oil supply. Despite a marked slowdown in production growth, preliminary data suggest that it accounted for around one-third of incremental supply in 2005. The CIS is the most important – and fastest-growing – oil-producing region outside OPEC. This paper assesses the potential long-term role of the CIS in global oil supply. Its major focus is on the degree to which fiscal and regulatory frameworks, and the broader institutional environment will facilitate or hinder the development of the region's oil resources. The main conclusions that emerge from this analysis may be summarised as follows:

- The CIS is set to remain both the largest oil-producing region outside OPEC and the largest source of incremental non-OPEC supply. Much of the former Soviet space is still underexplored, but there is reason to believe that its relative weight in world oil production is potentially even greater than current reserve estimates suggest. Whether or not this potential is realised, however, will depend on the establishment of appropriate fiscal, legal and regulatory regimes.
- Although the three largest producers in the region – Russia, Kazakhstan and Azerbaijan – adopted different strategies for developing their oil resources in the 1990s, all three were broadly market-oriented and largely reliant on private-sector initiative. This contributed to a strong recovery of investment and output in all three states after the initial post-Soviet contraction. The state-controlled oil sectors of Turkmenistan and Uzbekistan, by contrast, experienced far less disruption during the

1. The authors are grateful for the valuable comments received on earlier drafts of this text from Val Koromzay, Andreas Wörgötter, Vincent Koen and Doug Sutherland in the OECD Economics Department, Isabel Murray and David Fyfe of the IEA, Vladimir Milov of the Institute for Energy Policy, Evsei Gurvich of the Economic Expert Group attached to the RF Ministry of Finance, and Professor Paul Stevens of the University of Dundee. They also thank the many Russian and western officials, experts and businessmen, too numerous to list here by name, who discussed CIS oil issues with them. Finally, special thanks go to Corinne Chanteloup of the OECD Economics Department for technical assistance. The opinions expressed in the paper are those of the authors and do not necessarily reflect the views of the OECD or its member states.

2. *Vedomosti*, 27 September 2005.

early post-Soviet period but have since run into growing difficulties in trying to sustain output. Turkmenistan, in particular, is nowhere near realising its considerable potential.

- In recent years, however, policies in Russia and Kazakhstan have moved in a much more *dirigiste* direction. The state's direct role in owning and managing oil-sector assets has grown, sometimes as a result of quite heavy-handed action. This raises questions about the extent to which the growth potential of their oil industries will be realised over the longer term, particularly as geopolitical considerations seem to be increasingly prominent in government decision-making.
- While there can be little doubt that the role of CIS producers in global oil supply will continue to grow over the long term, that growth is likely to be slower than it would otherwise have been as a result of recent policy changes. The role of sovereign monopolies in the sector has grown, while private companies have been asked to accept lower returns on investment even as the authorities have acted in ways that increase political risk. This cannot but have a negative impact on investment decisions.

2. The paper proceeds as follows. The analysis begins with a brief examination of the global context and a look at the region's potential on the basis of its current production and estimated recoverable reserves. The succeeding sections focus on the institutional arrangements and policies that the various CIS producers have adopted since the Soviet collapse and on the results of these policies. The discussion then turns to recent shifts in the policies of the two largest producers, Russia and Kazakhstan. This is followed by a brief discussion of the implications of those shifts for the future. It is important to stress at the outset that the study focuses on the region's supply potential. There are many important oil-related issues it does not address, including questions such as the management of oil revenues and the policies available for combatting 'Dutch disease' and other problems associated with the so-called 'resource curse'.³ The paper does cover transportation issues, but it focuses on policy processes in this field rather than trying to identify specific routes and projects that are needed.⁴

2. The global context

3. Any assessment of the long-run supply potential of oil producers in the CIS must be set in the context of growing global dependence on OPEC over the long term. The IEA (2004) sees OPEC's market share rising from somewhat under 40% in 2002 to 53% in 2030, slightly above the historical peak recorded in 1973. Total non-OPEC reserves are being depleted faster than those of OPEC, and the world's oil reserves are more and more concentrated in a limited number of OPEC states, where investment is not allocated according to market forces.⁵ Increasingly, therefore, global oil supply will depend on what the members of the cartel do. This is a matter of particular concern, given that recent forecasts anticipate long-run average rates of growth of OPEC output of 2.5–3.5% per annum,⁶ which are actually well above long-run historic averages for OPEC production growth. If the cartel acts collectively, it may conclude that it

3. For detailed analyses of these issues, see Ahrend (2006); Gianella and Chanteloup (2006); World Bank (2005a); and World Bank (2005b).

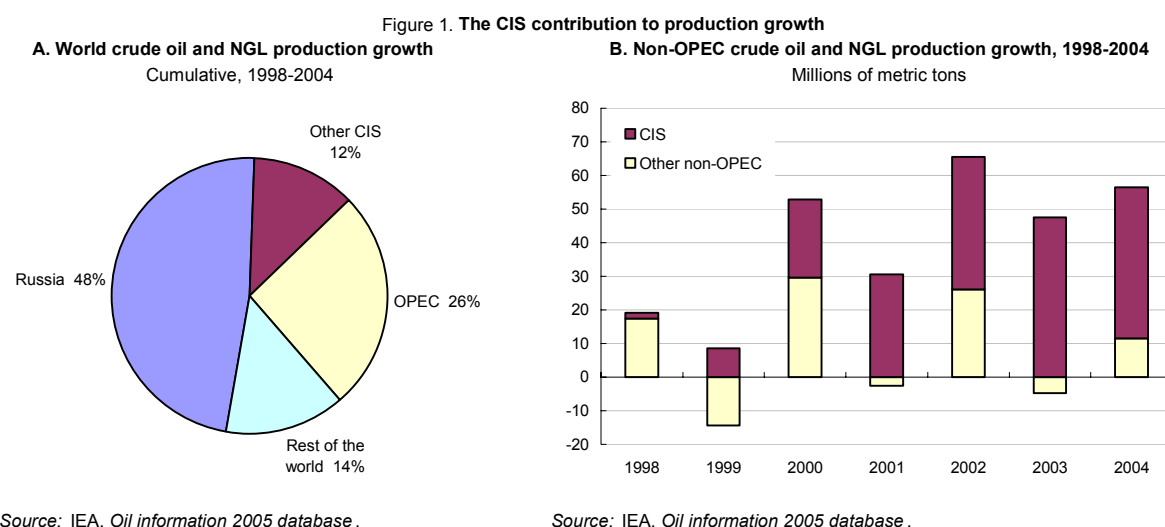
4. See Annex 3 for a brief overview of the state of the region's oil export infrastructure and the prospects for its future development.

5. Brook *et al.* (2004:13).

6. See, *e.g.*, IEA (2004) and USEIA (2002) and (2005). Significantly, the USEIA (2005) projections envisage much slower growth of OPEC output than did USEIA (2002).

has no incentive to increase output so rapidly and that it would be better off growing market share more slowly and profiting from higher prices.⁷

4. The CIS is both the largest oil-producing region outside OPEC and, at present, the principal source of incremental supply (Fig. 1). It is not destined to become in any sense a real rival or alternative to OPEC, but the prospect of rising dependence on OPEC – and, in particular, on Middle Eastern OPEC – makes the potential development of non-OPEC supply even more important, for at least three reasons: the general desirability of maintaining diverse supply channels; the potential for instability or threats to supply within much of the OPEC area; and the fact that what the cartel does as reliance on OPEC increases will depend in part on the elasticities of both non-OPEC supply and oil demand. The higher the long-run elasticities of both demand and non-OPEC supply, the greater will be the incentives for OPEC to increase production rather than to restrict output in an effort to sustain high prices.⁸ Higher elasticities would increase the potential for non-OPEC producers to act, at the very least, as “softeners” on cartel-like behaviour.⁹



5. The importance of non-OPEC supply is all the greater in view of the likelihood that recent sharp increases in world oil prices will be at least partly sustained over the coming years. To be sure, there is continuing debate about the degree to which cyclical, as opposed to structural, factors have been driving recent price hikes, but there is good reason to expect continuing market tightness over the medium term.¹⁰ At the same time, spare production capacity has fallen to historically low levels following a decade of low

7. For a detailed analysis of the incentives facing OPEC and its possible responses, see Gately (2004). Rehr *et al.* (2005) also take the view that OPEC has no economic incentive to push its market share much above 50% unless demand becomes much more price elastic. One could argue that the cartel may have trouble maintaining discipline, but the growing concentration of reserves in a few states may result in a better-functioning cartel. Even if cartel discipline broke down, it is not clear why members would want to ramp up production very rapidly rather than adopting a more cautious approach and keeping prices higher.

8. The impact of higher elasticities of demand and non-OPEC supply on OPEC's incentives would also be shaped by the awareness that these elasticities appear to be significantly asymmetric, since periods of high prices induce investment in energy saving technology and/or new production capacity that will not be reversed as and when prices fall. Cf Brook *et al.* (2004) and Gately (2004), appendix A.

9. Brook *et al.* (2004:6).

10. For recent analyses, see Brook *et al.* (2004); IEA (2004); and Kochhar *et al.* (2005).

oil prices and low investment. OPEC's spare capacity appears to have fallen to below 1.5mbd by the end of 2004 (around 2% of demand), as compared with a peak of around 10mbd (15% of demand) in 1985 and 'normal' levels of 3–5mbd in more recent years. Aggregate OPEC production capacity in 2005, though well above the lows reached in the early 1990s, was still below 1978 levels.¹¹ Expectations of long-term oil prices are critical to assessing likely developments in the CIS and with respect to non-OPEC supply generally. As Brook *et al.* (2004:13) point out, the long-run non-OPEC price elasticity of supply depends in part on whether or not the price change is believed to be permanent.¹²

6. Given that demand growth is expected to continue, the most contingent element in the picture is oil-sector investment, which will determine supply, and hence price (albeit with a lag). The IEA's latest (2004) global reference scenario anticipates cumulative global investment of around \$3trn in year-2000 US dollars (roughly \$105bn per year) during 2003–30, with exploration and development accounting for around 70% of the total.¹³ Most of this will be needed simply to replace existing capacity and offset the natural decline of currently producing fields; only about a quarter is likely to address rising demand.¹⁴ The IEA estimates that developing Russia's oil resources successfully will require around \$12bn per annum during the period to 2030 – roughly the level actually recorded in 2004¹⁵ – with the other Caspian littoral states needing roughly \$3.7bn a year over the period.

7. Whether or not such investment is undertaken in an efficient and timely manner will depend to a great extent on developments within CIS states, but their prospects must be viewed against the backdrop of a number of global factors that may tend to depress oil-sector investment generally. So far, there has been little sign of a strong investment response to recent price rises.¹⁶ Until recently, expectations of low oil prices rested in large measure on the assumption that any significant, sustained rise would generate a strong supply response in the form of investment in new capacity, as well as a slowdown in demand growth, but there has so far been little sign of either. Of course, supply and demand typically respond to price changes with a lag – it can take years for consumers to switch technologies and/or fuels, and most supply-side investment is characterised by long gestation periods.

8. There seems, however, to be more at work than a lag between initial investment and marketable output. Uncertainty about the sustainability of recent price rises clearly seems to form part of the explanation. Forecasting long-term oil prices is notoriously difficult and past price expectations have often proved to be far off the mark. The experience of past price collapses has doubtless had a restraining effect. Moreover, price volatility makes it harder to distinguish between temporary and permanent price

11. IMF (2005:9–10, 13). At the same time, global demand rose by 2.7mbd in 2004 – the largest single-year demand increase since 1976. In 2005, demand growth eased somewhat, falling back to around 1.6%, the average recorded for 1994–2003 inclusive (Yergin 2006).

12. Brook *et al.* (2004) also observe that the elasticity of non-OPEC supply may be non-linear. A certain level, the oil price would be high enough to stimulate investment in the production of unconventional oil and/or particularly difficult or high-cost locations.

13. This estimate is based on an assessment of investment needs using the methodology set out in IEA (2003).

14. IEA (2004:121) makes the important point that global investment needs will be more sensitive to changes in decline rates than to changes in oil demand.

15. Landes *et al.* (2005:61). Capital expenditure in the Russian oil sector (including upstream, refining and transport) is estimated at a record \$12.5bn in 2004, more than double the level of 2000.

16. The US consultancy John S Herold, Inc. has estimated the total capital expenditure of the Big Five international oil companies (BP, Total, ChevronTexaco, ExxonMobil and Royal Dutch/Shell) at \$65bn in 2004, up only marginally on 2003 in real terms and substantially down relative to their cashflow. See also Bahree and Barta (2004); Blum (2004); and Boxell and Morrison (2004).

movements. It thus contributes to volatility of investment returns, which increases the required expected return on capital and complicates investment planning.¹⁷ International oil companies in recent years have thus tended to base long-term plans on conservative long-run oil-price assumptions – in many cases, in the \$20–25/bbl range even in late 2004/early 2005.¹⁸ There is some evidence that planning prices have started to rise, at least for purchases of existing reserves,¹⁹ and upstream spending is accelerating. However, anticipated market volatility and uncertainty about longer-term price trends seems still to be restraining energy investment, raising the possibility of a ‘volatility trap’.

9. The backdrop to all these concerns, of course, is the market power of OPEC and, in particular, of Saudi Arabia, its ‘swing producer’. This power is likely to make for a continuing conservative investment approach on the part of non-OPEC companies. With little spare capacity but low development costs, Saudi Arabia could increase capacity fairly quickly if it chose to do so.²⁰ Ultimately, major oil companies’ reliance on relatively conservative assumptions about long-term average oil prices may reflect this. Non-OPEC producers, who generally face higher costs, may feel constrained to base investment decisions on a long-term price forecast that is at the lower end of what they believe Saudi Arabia and OPEC regard as their long-run target price range. Projects based on higher price forecasts could do the other producers considerable damage in the event that the cartel opted (for commercial or political reasons) to ramp up production and increase market share. However, the investment discipline exerted by OPEC’s power may also benefit the oil majors in the form of current windfall profits caused by their failure to invest more in the 1990s. The bias towards investment conservatism arising from OPEC’s market power thus needs to be recognised.

10. These considerations may matter more in the CIS than in some other regions, because CIS oil production and transport costs are considerably higher than those facing OPEC and some non-OPEC producers. The huge sunk costs involved in developing CIS petroleum resources, as well as the political and other risks that the region presents, mean that investors need to be confident that long-term average prices really will be high enough to warrant such investment. Yet the inherent uncertainty of price dynamics in oil markets makes it difficult to be sure of this. What is crucial to bear in mind during the discussion that follows is that CIS governments can do much to affect the long-run price that investors reckon they need in order to make large, long-term commitments: fiscal conditions, regulations and other measures that influence production and transport costs directly affect the returns to oil production, while

17. While the return on investment for downstream electricity and gas companies has been relatively stable, oil and upstream gas companies, especially exploration and development companies and oilfield equipment and service companies, have experienced relatively volatile returns.

18. Stevens (2004) and Osmundsen *et al.* (2005) argue that value-based management theories and pressure to focus on short-term returns to capital reinforce this conservatism. Faced with very high prices, companies have tended to raise dividends and engage in share buy-backs rather than increasing investment. See also Kar-Gupta (2004) on how investment announcements by oil companies can lead to *lower* stock prices, owing to investors’ preference for buy-back programmes and other mechanisms for channelling profits to shareholders.

19. Chevron publicly lifted its planning price to the mid-20s at the end of 2004, and its bid for Unocal in early 2005 implied a rise to perhaps \$30–35. *Financial Times*, 5 April 2005. BP has also indicated that it expects prices to remain at around \$30 or more for a long time, though it has not made any explicit statement about the planning price used to assess investment projects.

20. Saudi Arabia has, in fact, been adding capacity rather quickly, increasing it by 400kbd in 2004 and an expected 500kbd in 2005. Saudi Aramco plans to add an additional 2.3mbd during 2006–09, raising production capacity above 12mbd.

actions that increase or reduce risk for investors will also tend to raise or lower the expected rate of return required to justify investment.²¹

3. The role of the CIS in world hydrocarbons supply

11. The CIS, while in no sense a long-term alternative to OPEC, is the biggest producing region in the world outside OPEC and is likely to remain the most important source of non-OPEC supply for many years. Russia and Kazakhstan are particularly important, accounting together for over 90% of both proven reserves and crude production in the CIS (Table 1). Before considering the policy and institutional issues that will determine whether or not CIS oil resources are developed in a timely, economically efficient manner, it is necessary to examine the region's recent performance and longer-term potential.

Table 1. CIS oil sectors, 2004

	Proven reserves		Production		Exports
	bn bbl	% of world	000 bbl/day	% of world	000 bbl/day
Azerbaijan	7	0.6	318	1.3	211
Kazakhstan	39.6	3.3	1295	1.6	997
Russian Federation	72.3	6.1	9285	8.7	5140
Turkmenistan	0.5	0.4	202	0.3	80
Uzbekistan	0.6	0.05	152	0.2	0

Source: BP, USEIA, OECD calculations

Output recovery

12. The rapid recovery in CIS oil output in recent years, driven chiefly by the turnaround in Russian production, has been one of the most important developments affecting world oil markets (Fig. 2). From a peak of almost 12.7mbd in 1987,²² Soviet oil output fell by 17% during the final years of the Soviet period, a decline which accelerated sharply after the Soviet collapse, bottoming out at just under 7.2mbd. In the mid-1990s, however, a recovery began in Kazakhstan, followed by Russia, Turkmenistan and Azerbaijan.²³ By 2004, CIS output had reached 11.4mbd – still below the Soviet-era peak recorded in 1987 but up nearly 60% on the low of 1996. Russia alone accounted for about three-quarters of this increase (almost 3.2mbd), although Kazakhstan recorded the most impressive growth rates, roughly tripling production in the ten years to 2004. The rapid expansion of Caspian output was not unexpected, in view of the on-going development of substantial new fields by foreign consortia, but the Russian recovery was a tremendous surprise to most observers, who consistently under-predicted CIS, and particularly Russian, output growth during 1996–2004.²⁴

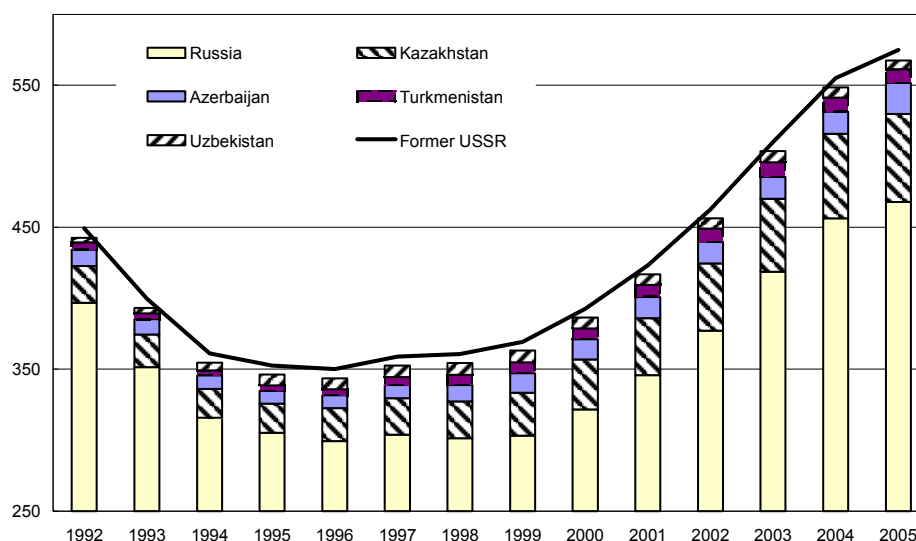
21. In respect of Russia, in particular, Dienes (2004) argues that it is institutions and politics, rather than geology and technology, that will really determine Russia's future oil-production profile.

22. Including both crude oil and natural gas liquids.

23. The exception to this trend was Uzbekistan, which managed to sustain production growth through the 1990s, with output nearly tripling to 191kbd in 1998–99 before falling just over 20% over the subsequent five years. However, in addition to being a minor producer, Uzbekistan was a significant oil consumer. Oil exports were limited, as rising output was needed to cover domestic consumption.

24. IEA (2004:525) notes that from 1995 through 2002, each of its successive global projections *raised* forecasts for non-OPEC supply to 2010, yet each was low of the mark, with the CIS accounting for most of the difference. The IEA, which was explicitly conservative in its projections, was not alone: most forecasts, including those of CIS governments, pointed to slower growth than was actually achieved.

Figure 2. **Production of crude oil and NGL**
Millions metric tons

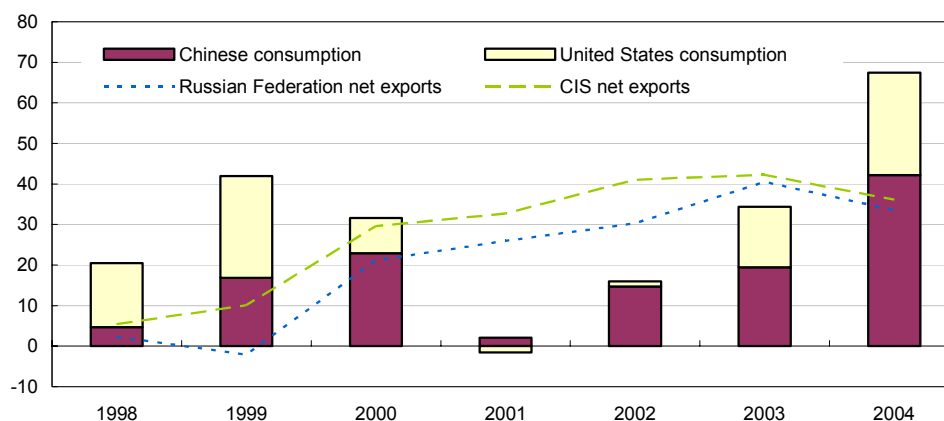


Source: IEA, *Oil information 2005 database*. Data for 2005 are preliminary.

13. The recovery of CIS oil production was as important as it was unexpected for global oil markets, especially once oil demand began to recover and prices to rise after 1998. During the six years to end-2004, CIS producers accounted for just over 60% of the increase in world output and 82% of the increase in non-OPEC output (Fig. 1). The CIS share of global production climbed by almost half over the period, from 10.0 to 14.4%, while the former Soviet Union's (FSU) share of world exports rose from 8.9 to 13.4%.²⁵ This contribution was critical at a time of rapid demand growth. Increases in CIS output during 1998–2004 came close to matching the combined consumption growth of the United States and China (roughly 4.2mbd), by far the two largest sources of demand growth over the period (Fig. 3). The IEA (2004), moreover, expects the non-OPEC share of world supply to continue growing to the end of the present decade, albeit with Kazakhstan and Azerbaijan accounting for an increasing proportion of incremental CIS supply. In both republics, projects now well under way should assure continued robust output growth through 2010.

25. Unfortunately, the available data on net exports are for the region of the former Soviet Union as a whole, not just the CIS, as the available data series do not separate out the Baltic states – their consumption is counted as part of the FSU total, not in net exports. National export data for the CIS oil producers *is* available, but it includes exports to other CIS states and, indeed, to one another (some Kazakh exports go to Russia, thus freeing up Russian oil for export, etc). Thus, the best available measures of supply to the rest of the world are still the data series on the FSU.

Figure 3. The growth of United States and Chinese oil consumption and CIS net exports
Million tonnes



Source: BP, *Statistical review of world energy*, 2005.

14. In Russia, by contrast, there are expectations of much slower output growth. The growth of Russian oil production since 1996 has resulted chiefly from rapid increases in output from already producing fields, made possible largely by the application of new technologies and, in many cases, the employment of western oil service companies. Russia has thus constituted a temporary exception to the rule that oil supply tends to be relatively inelastic in the short run: while the output recovery actually preceded the rise in prices, strongly increasing oil prices enabled Russian producers to increase upstream capital expenditure very rapidly, with most of this increase directed towards increasing production from existing fields (Table 2).²⁶ Clearly, rapid growth cannot continue indefinitely on this basis: it represents a transitional, recovery phase. While there is probably scope for a few more years of reasonably good growth on the basis of further production increases from existing fields,²⁷ sustained growth over the long term will depend increasingly on the development of new fields, both in West Siberia, where Russian production is now concentrated and where a number of sizable fields remain to be developed, and in less developed regions in the north and east of the country, as well as around the Caspian. These are proceeding relatively slowly: the Institute for Energy Policy estimated in mid-2005 that new fields would add only about 800kbd to Russian production over the period to 2009 (Milov, 2005). Dienes (2004) and Gaddy (2004) both anticipate that Russian oil production will shortly reach a peak, followed by a possibly steep decline, in part because the recent production surge has accelerated the depletion of existing fields, while far too little has been done to develop new ones. They believe that it is already too late to bring enough new production on-stream over the next decade to offset the decline in production from mature fields.

26. Estimates of capital expenditure are based on company data, which may differ from official statistics provided by the Federal Service for State Statistics (Rosstat) or the Ministry of Industry and Energy. However, all such financial data on the Russian oil sector should be viewed with caution, owing window-dressing in company accounts, problems with different accounting standards and other difficulties; in general, data on physical volumes of production, exports, etc. are more reliable.

27. See OECD (2004:57–8); Collison *et al.* (2004); Khartukov and Starostina (2005:48); and Aton (2005).

Table 2. **Russian oil-sector investment, output and exports**
1998=100

	1999	2000	2001	2002	2003	2004
Upstream capital spending	65	148	215	167	194	206
Crude and condensate production	101	107	115	125	139	151
Crude oil exports to non-CIS markets	98	118	125	139	156	183

Source : Ministry of Energy, InfoTEK, Renaissance Capital estimates, RIATEC, OECD calculations.

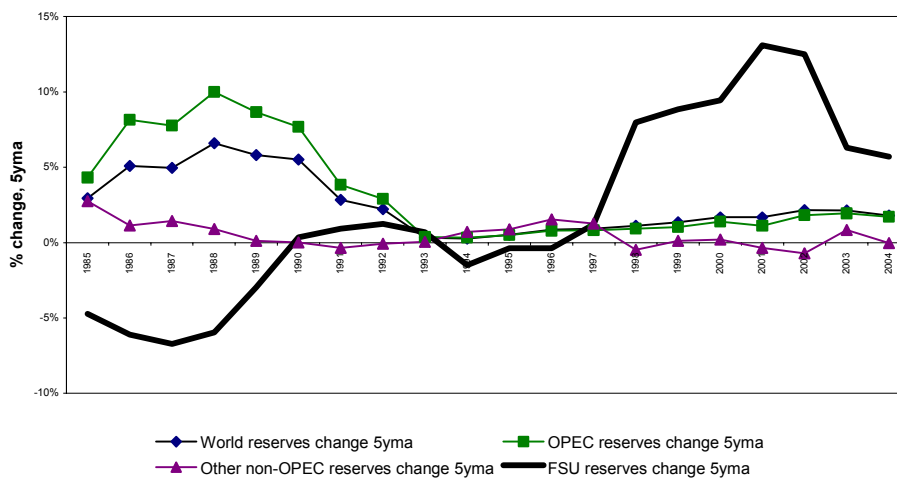
Oil reserves and long-term potential

15. The CIS appears to set to remain the most important oil-producing region outside the Middle East for some time to come. To be sure, assessments of its potential vary widely, depending on methods and definitions. There are considerable differences in estimates of the total volume of petroleum physically in place. Judgements about how much of this can be produced economically depend on assumptions about technological development, oil price trends and other variables (Annex 1). BP (2005) estimates CIS proven reserves²⁸ at just under 121bn bbl, up 28.5% over five years. Russia accounts for 60% of this total, with 72.3bn, followed by Kazakhstan with 39.6bn.²⁹ This leaves the CIS with 10.2% of world reserves and 40.5% of non-OPEC reserves, compared with a 61.7% share of world reserves for the Middle East as a whole, led by Saudi Arabia's 22.1%. Moreover, the CIS has, in recent years, been the only major region to record strong reserves growth, although this partly offsets very slow growth during the late 1980s and early 1990s (Fig. 4).

28. 'Those quantities that geological and engineering information indicates with reasonable certainty can be recovered in the future from known reservoirs under existing economic and operating conditions'.

29. While all CIS reserves data must be treated with caution, estimates for Uzbekistan and Turkmenistan are particularly problematic, since foreign involvement is so limited and the regimes in question are so secretive. BP's estimates for these states have remained unchanged for some time, and may therefore be off the mark. In the case of Turkmenistan, however, alternative estimates suggest that reserves may be close to triple the levels reported by BP. IEA (2005c:4) cites estimates running to around 11bn tonnes for the Turkmen section of the Caspian alone.

Figure 4. Change in oil reserves



Source: BP Statistical Review of World Energy 2005, OECD calculations.

16. There is good reason to believe that the CIS share of both reserves and output could rise further. Much of the CIS, including some geologically promising regions of Russia and Kazakhstan, is still under-explored, and relatively little exploration is taking place at present.³⁰ On the basis of data for 1996, the US Geological Survey (USGS) estimated that the former Soviet Union held just under 17% of as-yet undiscovered, technically recoverable oil in the world. This is based on the mean probability for the USGS estimates, which cover a range of probabilities, from 5% to 95%. Significantly, the estimated potential FSU share is substantially larger than its actual 2004 share across the whole range of estimates for different probabilities. The USGS figures have been subjected to some sharp criticism,³¹ but they remain the most comprehensive and authoritative estimates of undiscovered recoverable reserves in the world. Moreover, criticism has been focused on the possible upward bias of the overall estimates, rather than their distribution. If the critics are right, there may be a substantially lower total volume of undiscovered oil than the USGS data suggest, but it is still likely that the potential CIS share is substantially larger than its current relative weight in proven reserves.³²

17. This conclusion is also supported by other recent estimates. De Golyer and MacNaughton suggest that the recoverable reserves of Russia alone could amount to about 150–200bn bbl and an assessment by

30. The question of exploration is discussed below and in Annex 1.

31. See, e.g., Greene *et al.* (2003); Aleklett (2004); Ferguson (2005). The probability estimates refer literally to the probability that as-yet undiscovered recoverable oil reserves are present. The highest figures are thus for the 5% figure, covering reserves that probably are not there to be found, while the much smaller 95% figure estimates quantities that are reckoned almost certain to be there. Sceptics argue that the actual figures are probably rather lower than the Survey's 'mean probability' estimates, somewhere between its 5 and 50% estimates.

32. It should also be noted that the USGS estimates cited here are for undiscovered oil; they do not include potential reserves growth via increases in the share of oil known to be in the ground that is assessed as economically recoverable. There is considerable scope for growth in the CIS here, too, although a great deal of the easiest growth in this respect has already taken place.

IHS Energy (formerly Petroconsultants) put Russia's resource potential at 140bn bbl at end-2001.³³ There are also wide variations in assessments for Kazakhstan and Azerbaijan.³⁴ World Bank (2005b:3) cites estimates as high as 53.9bn barrels for the former, compared with BP's figure of 39.6bn. According to Energy and Natural Resources Minister Vladimir Shkolnik, a seismic survey of the North Caspian conducted in 1994–96 identified 23 areas with large or medium-sized structures likely to hold oil in the Kazakh sector of the sea. It would be unrealistic to expect that the North Caspian will yield any further discoveries on the scale of the giant Kashagan field, discovered in 2000. However, if only half of these prospects prove to be productive, they could add a further 5–6bn barrels. Together with enhanced recovery from existing fields, this could raise Kazakh reserves to the 50–60bn barrel range.³⁵ Estimates for Azerbaijan are much lower, but estimates of proven reserves run as high as 13bn barrels, and the government itself has claimed 17.7bn, albeit on the basis of the old Soviet system for classifying reserves.

The challenges ahead

18. It can by no means be taken for granted that the potential just outlined will be developed in a timely, economically efficient way. On the contrary, many observers, including IEA (2004), anticipate that CIS output will stagnate or decline after 2010, owing chiefly to developments in Russia.³⁶ Whether or not existing hydrocarbon resources are developed will depend critically on the institutional environment and on the policies pursued by CIS governments. While the impact of geology, geography and international price movements can hardly be ignored, there is much that policy-makers can do that could raise or lower the long-term elasticity of CIS supply. Indeed, fiscal, regulatory and institutional frameworks may actually matter rather more in the coming decades than they have hitherto – not only in the CIS but in most of the oil-producing world. As noted above, market volatility, capital discipline and an awareness of OPEC's market power all constitute incentives for major oil companies to be more conservative in their planning and investment decisions. In such circumstances, fiscal and regulatory policies that unduly increase the risks facing investors add to the disincentives to invest, pushing up the expected rate of return required to justify investment.³⁷ It is expected, moreover, that new oil finds will generally be smaller than in the past and that an increasing proportion of output will come from offshore or other difficult-to-develop fields, involving higher production costs and much more extensive up-front investment in infrastructure and equipment.³⁸ Project economics may thus be more sensitive to institutional and policy variables, as there is

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- 33. Bush (2004). DeGolyer and MacNaughton predict that by 2012 Western Siberia will be able to increase oil production from the current slightly less than 6 million barrels per day to 10 million barrels per day and to retain this level for at least a decade.
 - 34. Caspian reserves have long been a matter of debate: IEA (1998:32) notes that estimates of proven oil reserves in Central Asia and Transcaucasia then ranged between 15 and 40bn bbl, with a further 70–150bn bbl considered possible.
 - 35. See Kochhar *et al.* (2005:23), table 3; and World Bank (2005b:3), table 5.
 - 36. The Russian Ministry of Industry and Energy is similarly pessimistic, anticipating cumulative crude production growth of just 7.9–9.7% over 2004–08. See also Hill (2004), who argues that Russian oil production is in danger of repeating a historic cycle of underinvestment leading to difficulties sustaining production growth before renewed investment generates a revival. USEIA (2005) is much more optimistic, anticipating continued, albeit slowing, growth of both Caspian and Russian production through 2025.
 - 37. In effect, governments may seek to capture a larger share of oil rents (and thus to reduce investors' returns) while increasing the rates of return that a rational investor would require.
 - 38. See IEA (2002a:34).

likely to be less margin for error.³⁹ This could, of course, constitute an important source of pressure for reform over the long run. However, it raises the risk of long delays in developing new deposits, as governments may be reluctant to accept the reforms that are needed to attract investment, especially with respect to operational control.

19. To these problems, which are common to oil producers around the world, must be added the particular difficulties that CIS producers face in getting their output to market. These arise as a result of two factors. The first is geography. Most CIS production takes place well inland in Eurasia, often in very difficult geological and climatic conditions. The Caspian basin producers (except Russia) are landlocked, and even Russian production is generally a fairly long way from the sea. The country relies on a network of long overland pipelines and has relatively limited access to open water. Russia's main maritime export routes, via Novorossiisk on the Black Sea and Primorsk on the Baltic, both suffer from severe winter weather and sit astride routes that are increasingly problematic on account of congestion – the Turkish and Danish straits respectively.⁴⁰ The second problem is that the bulk of the export infrastructure was inherited from the Soviet Union. The pipeline network, in particular, was designed primarily for domestic distribution and with the needs of a centrally planned economy in mind. While there has been considerable investment in maintaining and expanding export infrastructure, much remains to be done if infrastructure constraints are not to become an impediment to future growth in oil exports from the region. Infrastructure policies will thus be critical to realising the region's long-term hydrocarbons potential. (See Annex 3 for a detailed look at export infrastructure problems.)

20. A related problem for Caspian producers will be a final resolution of the status of the Caspian Sea itself, which has been contested since the collapse of the USSR at the end of 1991. Russia and Iran, harking back to the Caspian Sea conventions signed by the Soviet Union and Iran, initially insisted that the sea was an inland body of water (a lake) and must therefore be exploited exclusively through a condominium of all five states.⁴¹ Azerbaijan and Kazakhstan insisted that the Caspian was a sea, which should be divided into separate territorial waters. Turkmenistan's position shifted during the course of the 1990s and was not always entirely consistent. This did not prevent a number of bilateral deals among Caspian littoral states, nor did it stop development of the Caspian's hydrocarbon reserves – even Russia came gradually to accept *de facto* that the Caspian should be treated as a sea. In May 2003, Russia, Azerbaijan and Kazakhstan formalised this understanding in a trilateral agreement on sub-surface boundaries and collective administration of the sea's waters. They divided up the northern 64% percent of the Sea using a median line principle.⁴² This opened up opportunities to develop the northern part of the sea, despite the refusal of Turkmenistan or Iran to sign the agreement.⁴³ However, offshore development of other sectors will have to await a more comprehensive settlement. At present, entire fields remain untapped due to the lack of clarity about ownership. Moreover, trans-Caspian pipelines are unlikely to be constructed

39. In the long run, this could actually contribute to improvements in institutions and policies, as governments may find that they cannot secure the investment and technology needed to tackle such projects without offering better conditions to investors.

40. Of course, Russia also has considerable offshore oil resources, some of which are already being developed. Projects on the shelf are not subject to the same difficulties with respect to transport, but they present considerable technical difficulties of their own.

41. This would have given Russia and Iran, with scant offshore hydrocarbon deposits of their own, an effective veto over the exploitation of the others' offshore fields.

42. The agreement allocated 27% of the seabed to Kazakhstan, 19% to Russia and 18% to Azerbaijan.

43. Turkmenistan favours a modified technique for applying the median line principle, one that would give it possession of Azerbaijan's largest offshore deposits, while Iran, which would secure just 12% of the seabed under the median line principle, wants the sea divided into equal shares.

without an agreement on ownership of the waters, seabed and resources. Even the regulation of tanker traffic on the sea remains controversial.

Box 1. What about demand in the CIS and the Baltic States?

Of course, the CIS's role as a net supplier of petroleum to the rest of the world depends on domestic demand trends as well as what happens on the supply side.¹ Most observers expect that overall FSU energy demand growth should remain relatively subdued for some time to come. The CIS economies, in particular, are extremely energy-intensive. In Russia, energy consumption per dollar of GDP in 2003 was estimated to be 2.3 times the world average and 3.1 times the European average (calculated on the basis of purchasing power parity).² The situation of other states in the region is not dissimilar. To some extent, such high ratios of energy consumption to output are a product of factors such as geography, climate, the structure of industrial production inherited from Soviet central planning and the energy inefficiency of the industrial plant and infrastructure created during the Soviet period. These factors were compounded by the sharp fall in GDP during the 1990s – output fell far faster than energy consumption, so the energy intensity of GDP rose. Consequently, the growth of recent years has tended to reduce the energy intensity of GDP.

There is undoubtedly considerable scope for further substantial reductions in the energy intensity of production in the post-Soviet states, because progress in improving energy efficiency in most of the region has been relatively slow. Formal policies aimed at increasing energy efficiency in both consumer and producer states in the region have generally achieved little, owing to lack of both public and private finance, and weak incentives. Energy prices have generally remained at artificially low levels, and billing arrangements often provide for little consumer control or incentive for efficiency. Competition in electricity and heat sectors is either non-existent or has only recently begun to develop. However, all these factors are changing. Price developments are particularly important: energy prices within Russia have been rising relatively fast in recent years, as have those charged by Russia to other CIS countries and the Baltic states. Without economically meaningful energy prices, the incentives to increase efficiency will be too weak. The Russian government estimates that the country could reduce energy consumption per unit of output by almost half from current levels,³ and many of its CIS neighbours could do likewise. However, the implications of this trend towards greater efficiency for crude oil demand are unclear: crude consumption may rise relatively rapidly compared to other fuels, owing to changes in consumption patterns, including a rapid expansion of automobile ownership.

Wood McKenzie (2005) estimates that FSU oil demand will increase from 3.6mbd in 2003 to 4.1mbd in 2006. This means that growing demand in the region will, on the Wood McKenzie estimates, consume about one-quarter of the production increase over the period. The longer-term outlook is less clear. IEA (2004) has Russian domestic oil demand rising at the same rate as output (1.9% pa) for 2002–10, but demand thereafter grows slightly faster than output. The IEA reckons that that Russia's net exports will peak around 2010, with consumption growth in excess of incremental production after that. USEIA's (2005) long-term forecasts for the entire FSU region show demand growth accelerating sharply, to around 2–3% per annum after 2010, even as the region's production growth slows. From around 2015, the USEIA sees production growth falling well below the rate of demand growth. However, incremental production will continue to be larger than incremental demand in volume terms, because the growth will be from a higher base. Thus, FSU supply to the rest of the world would, in the USEIA's base case, continue to increase through the end of the forecast period (2030), albeit by only about 70–100kbd per year after 2015.

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1. Demand, like net exports, is discussed in terms of the FSU (CIS + Baltic States), owing to the fact that the available data and projections cover the Baltic states together with the CIS countries.
 2. 'Energeticheskaya strategiya', (2003:21). See also the even more pessimistic estimates in ISDEI (2003).
 3. 'Energeticheskaya strategiya', (2003:21).

4. Patterns of ownership, control and taxation

21. In the years following the collapse of the Soviet Union, the petroleum producers among its successor states adopted a range of different strategies for managing and developing their hydrocarbons sectors. Patterns of ownership and control, as well as tax regimes, and attitudes towards both the extent and

the modalities of foreign involvement varied widely.⁴⁴ There were and are, of course, a number of common features of the investment environment in all the CIS producers. These include a generally weak institutional framework, pervasive corruption, opaque and often changeable policy-making on the part of the authorities, and relatively high levels of political and economic uncertainty. To be sure, such problems are hardly unique to the CIS. Much of the world's oil production originates in countries afflicted by similar problems. However, some western oil executives with experience elsewhere in the world privately report finding the CIS a particularly difficult place to operate, particularly with respect to corruption. There is some evidence, moreover, that these sentiments are widely shared: in recent years, former Soviet republics have consistently ranked below most other major oil exporters in Transparency International's Corruption Perceptions Index.⁴⁵ In addition, the legacies of the Soviet past – including both physical infrastructure and institutions – and the problems of post-communist transition confront local and foreign oil companies with a unique set of challenges. Nevertheless, an awareness of the different paths taken by CIS producers is critical to understanding their development over the past decade and the challenges they now face. The following sections review the development of oil policies from the fall of the USSR until 2003. This discussion is followed by an examination of more recent shifts in oil policy in Russia and Kazakhstan.

Russian Federation

22. Perhaps the most unusual path was that taken by Russia: by the late 1990s, the Russian oil industry was overwhelmingly in the hands of private Russian owners. This made Russia almost unique not only in the CIS but among major oil exporters around the world. State ownership is the global norm and Russia was by far the largest petroleum exporter whose sector was not dominated by a state company or companies (though in many countries state-owned petroleum companies operate as partners of private foreign companies).⁴⁶ While the state continued to play an important role in the sector and even retained ownership of some oil companies, the industry was dominated by privately owned domestic companies. The authorities created a number of vertically integrated companies (VICs) by presidential decree in the early 1990s and subsequently privatised them, often via highly questionable processes.⁴⁷ The largest part of oil-sector assets left state hands via the notorious loans-for-shares process of 1995–97, when the state transferred control over some of the country's most valuable enterprises to politically well connected domestic business interests at extremely low prices.

23. Some oil companies were privatised into the hands of insider managers who were oil industry professionals (so-called *neftyaniki* or oilmen), while others were acquired by politically well connected financial groups (the so-called *finansisty*), usually after those same groups had secured the allegiance of insider managers within the companies in question.⁴⁸ The distinction between the *finansisty* and the *neftyaniki* turns out to have been an important one, as the strategies pursued by the companies in the decade since privatisation have tended to reflect to some extent the different orientations of the two types of owner.⁴⁹ The initial wave of insider-oriented privatisation was followed by a process of consolidation.

44. On the reasons for these divergent choices, see Jones Luong and Weinthal (2001) and Jones Luong (2004).

45. The major exceptions are Angola, Indonesia (now, in any case, a net oil importer) and Nigeria (which consistently occupies second-to-last place in the index).

46. Russia's gas sector, still dominated by a state-controlled, vertically integrated monopoly, is in this respect much closer to the norm worldwide.

47. For a detailed look at the privatisation of the Russian oil sector, see Lane (1999).

48. See Thompson (2002); in this respect, the loans-for-shares transactions resembled the insider-orientation of most Russian privatisation.

49. See OECD (2004:42–4). Gaddy and Ickes (2005) also treat the *finansist*- and *neftyanik*-controlled companies as distinct subgroups.

The larger VICs, which were privatised relatively early, bought up additional oil-sector assets as they were privatised and also swallowed up some of their smaller rivals – often employing methods as controversial as those that characterised the loans-for-shares sales. This left the industry dominated by a handful of the larger privatised VICs; by 2004, the top four private companies accounted for over 60% of output and almost 58% of exports (Table 3).⁵⁰

Table 3. Major Russian oil producers, 2004

Company	Output (mt) ¹	Non-CIS exports (mt) ²	Refining (mt)
Yukos	85.7	31.3	31.9
Lukoil	84.1	29.3	35.5
TNK-BP	70.3	36.3	21.6
Surgutneftegaz	59.6	22.4	15.9
Sibneft	34	13.1	14.3
Tatneft	25.1	9.8	6.7
Slavneft	22	3.9	12.4
Rosneft	21.6	8.2	9.5
Bashneft ³	12.1	–	18.3
Gazprom	12	0.4	6.4
Others (including JVs)	32.5	51.92	40.8
Total	485.8	206.6	195.0

¹ Includes crude oil and condensate.

² Data on exports by company includes only shipments carried by Transneft and exports from proprietary terminals. Rail, river and other bypassing deliveries are included in 'others'.

³ Data on Ufa-based refineries

Source: InfoTEK, Ministry of Energy and Industry, Renaissance Capital.

24. While the VICs were privatised relatively rapidly and allowed to pursue their own development strategies, the state kept a tight grip on the sector's infrastructure, particularly the oil pipeline monopolist, Transneft. Since export infrastructure was and remains a scarce commodity, this constituted an important check on the power of the oil companies. Moreover, since all producers were dependent on the trunk pipeline network inherited from the Soviet system, there were strong arguments for operating it as a publicly owned natural monopoly. It would have made little sense to privatise Transneft in the 1990s, as a whole or following some sort of break-up. Nevertheless, Transneft's position proved to be problematic in certain respects. Producers of better quality crude suffered losses as a result of Transneft's failure to operate a quality bank, and the imposition of special charges to finance specific projects like the Chechnya bypass and the Baltic Pipeline System meant that oil producers were being made to pay for the construction of infrastructure they might never need or use. Moreover, although Transneft is, in principle, simply a regulated fee-for-service carrier, it has sometimes served as a regulatory instrument enabling the state to maintain a firmer grip on the Russian oil sector and to exploit its position as a key transit state for other CIS producers. As will be seen, the problems with Transneft's role have grown more acute as oil output and exports have risen and the development of new transport infrastructure has become an ever more urgent concern.

25. A number of arrangements for rationing export pipeline capacity were employed during the years following the Soviet collapse and many others were debated, some of them quite complex,⁵¹ but the system has in recent years rested on the principle of 'exports proportional to output'. Export volumes thus depend on production volumes for the previous quarter, albeit with some exceptions. Most large Russian oil

50. IEA (2004:307) notes that the tax system tends to favour larger companies, a factor that may have facilitated this consolidation process. The large VICs' appetite for acquisitions was also aided in many cases by the weak institutional environment, which enabled them to manipulate privatisation processes, bankruptcy proceedings, etc.

51. For details see IEA (2002a:92–94).

companies seem reluctant to contemplate any move away from the proportionality formula, which, though subject to various exceptions and sometimes *ad hoc* adjustments, is generally regarded as fair, transparent and predictable.

Box 2. Foreign investors and Russian oil in the 1990s

Foreign access to privatisation deals in the 1990s was almost entirely blocked. This was not as much of a constraint on foreign penetration as it might appear, as most foreign oil companies initially tended to be more interested in entering Russia via joint ventures (JVs) or production-sharing agreements (PSAs) rather than by purchasing equity in Russian oil companies. Their appetite for Russian oil companies' equity developed later.¹

Foreign activity in the sector thus remained limited and was concentrated in a few large projects such as those on and around the island of Sakhalin, developed on the basis of production-sharing agreements (PSAs) negotiated in the early 1990s. Not coincidentally, such projects were usually in new and difficult oil regions, where foreign expertise and technology were badly needed and where there were no entrenched Russian incumbents to resist perceived foreign encroachment. Hopes for other foreign-financed projects to develop new fields on the basis of PSAs failed to materialise. Although a framework law on PSAs was adopted in 1995, it had little impact owing to the authorities' failure to complete the legal framework needed for PSAs to function effectively.² The procedures for negotiating and concluding PSAs were cumbersome in the extreme, the relevant tax code chapter was stalled for years, and much of the legislation that was passed clearly contradicted other legislation.

Much work on perfecting the legislative framework for PSAs was undertaken in 2001–02, but opponents of PSAs stepped up their lobbying, and in early 2003, the government decided that PSAs would be employed only in a small number of exceptional cases. The licence to exploit a field must first be put up at auction or tendered in some other way on the basis of the normal tax and royalty regime. Only if no bidders are found on such terms will the state consider concluding a PSA.

To be sure, it was never intended that PSAs would form the basis for the fiscal regime in the oil sector. They were seen as a transitional arrangement to facilitate investment while the country developed its tax code and regulatory framework. In the event, however, the authorities in the 1990s neither completed the PSA regime nor created a stable, efficient taxes and royalties regime.

1. The most prominent exception to this rule was BP, which purchased a 10% stake in Sidanko for \$500m in 1997. The Sidanko deal was followed by the financial collapse of 1998 and a successful attempt by TNK to take control of two key Sidanko subsidiaries, Kondpetroleum and Chernogorneft. The legal and political battles that ensued proved extremely costly to BP and illustrated many of the reasons why Russia was a dangerous place to do business, from the weakness of the rule of law to the readiness of the political authorities to meddle in commercial disputes. Nevertheless, BP persevered with its involvement in Russia, eventually reaching a settlement with TNK and subsequently taking a 50% stake in that company.

2. To date, only three PSAs have been concluded, two of which were authorised by presidential decree prior to the adoption of the 1995 law. These include Sakhalin 1 and 2, offshore in the Far East, concluded in the early 1990s, and Kharyaga, in the Yamalo-Nenets Autonomous Okrug, signed in 1995. The three projects account for just 1.3% of proven oil reserves and 0.7% of proven reserves of natural gas. By contrast, most of Kazakhstan's oil resources are being developed under PSAs, with the Kashagan project alone accounting for perhaps a fifth of the country's proven reserves.

26. While the *formal* tax burden on the sector in the 1990s was rather heavy – if all taxes were paid, the average producer in the 1990s often faced tax bills in excess of his operating margin, rendering extraction unprofitable⁵² – the *effective* tax burden appears to have been substantially lighter, owing to the use of transfer pricing and other mechanisms to evade taxation.⁵³ Thus, Vasil'eva and Gurvich (2005) find

52. See IEA (2002a:79–80) for details. Although effective tax rates were lower than they appeared at first sight in the 1990s, the formal tax system nevertheless constituted a significant problem, owing largely to its profit-insensitivity. This is addressed below.

53. On the scale of transfer pricing in Russia's oil sector, see World Bank (2004:74–90).

that the total effective tax burden on the fuel sector in 2000 amounted to just 31.8% of the sector's value added. However, the effective burden on individual producers varied widely, owing to distortions in the tax system itself. The corresponding figure for non-fuel industry was 43.7%, while that for transport and communications was just under 41%. Tax changes introduced during 2000–03 served to correct the situation somewhat, as the effective tax burden on the fuel sector rose by an estimated 7% of value added while the burden on non-fuel industry *fell* by almost 8.5%.⁵⁴ Nevertheless, the sector remained highly profitable and the effective tax burden on the industry in 2003, estimated at 38.9% of value added, was not far out of line with the average for non-fuel industry (35.3%). Since then, the tax burden on oil producers has increased markedly as a result of formal increases in the main oil-sector taxes, much tougher tax enforcement in the wake of the Yukos case and the mechanical effect of oil price rises on the rates of the major oil taxes. As oil prices have risen, the state, as the ultimate owner of Russia's oil reserves, has become ever more determined to capture the rents arising from high prices. The state has every right to want to secure these rents, but the *means* it has employed have done considerable damage to the industry in the short run, as well as posing problems for its longer-term development. As will be seen, the crucial problem is not simply the overall level of the tax burden, but the profit-insensitivity of the system and the distortions this creates.

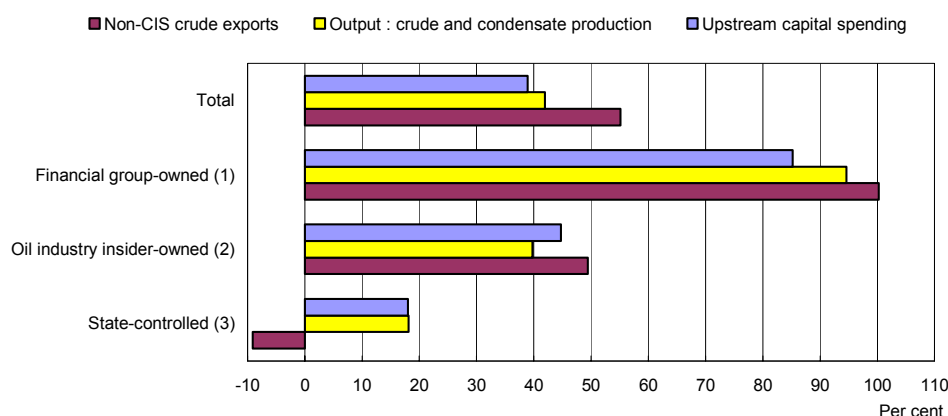
27. The combination of private ownership and low (effective) taxation proved extremely effective in generating a rapid recovery of output. Production began to recover, albeit slowly, around the time that the new owners took control of the privatised VICs and began to restructure them. Output growth accelerated sharply after the 1998 financial crisis, as the recovery in oil prices, coupled with the perception that property rights had become sufficiently secure, contributed to a strong recovery in investment, output and exports (Fig. 5). Oil-sector investment jumped from roughly 25% of industrial investment before the crisis to around 35% in 2004. Strikingly, the investment revival began with companies controlled by the state or by the *neftyaniki*: by 2000, their investment was already 70% above 1998 levels.⁵⁵ By contrast, oil companies owned by the major financial groups, whose owners' property rights were perceived as less secure, were investing only marginally more than in 1998. In 2001, however, as perceptions of the security of property rights further improved, the latter group of companies began rapidly increasing investment, soon reaching levels comparable with the former group. This investment led to a sharp increase in oil production and exports in the following years. Output growth, however, was uneven. During 1998–2004, *neftyanik*- and *finansist*-controlled companies increased output by roughly 75% and 56% respectively, with the output of the three largest *finansist*-owned companies up by 132%. State-controlled companies increased output only marginally. The picture with respect to exports is even more extreme. While the non-CIS exports of state-controlled companies fell, non-CIS exports were up 49% in the *neftyanik*-controlled companies and 105% in the *finansist*-controlled companies (almost tripling in the three largest).⁵⁶

54. General taxes, like VAT, were cut, while taxes specifically targeted at the fuel sector were raised. This process continued in 2004–05.

55. This assessment is consistent with the available data sources; however, the caveats provided in note 26 above, concerning the reliability of investment data, still apply.

56. Clearly, there may be an element of selection bias at work here, at least with respect to the production and export data: the privatisations of the 1990s did leave the state with many of the sector's less attractive assets. However, this is unlikely to be the whole story, not least because it would not explain their failure to invest or to take greater advantage of opportunities for enhancing recovery from mature fields with the help of oil services companies. Moreover, the differences in the performance of *finansist*- and *neftyanik*-controlled companies appears to be primarily the product of choices made by the new owners.

Figure 5. **Oil companies: relative performance**
Growth 2001-2004 inclusive



1. Sibneft, TNK, YUKOS.

2. LUKOIL, Surgutneftegaz.

3. Bashneft, Rosneft, Tatneft.

Source: Ministry of Energy, InfoTEK, Renaissance Capital estimates, RIANTEC, OECD calculations.

28. The obviously flawed nature of oil privatisation notwithstanding, the oil industry that emerged after 1998 proved very dynamic. It was, indeed, the most important single driver of Russian growth during 1998–2004.⁵⁷ It is important to note that oil production began to recover even before oil prices started to pick up in 1999. The decisive factor appears to have been privatisation – clarification of ownership helped take oil producing enterprises ‘out of limbo’, and output grew fairly steadily after 1998 regardless of the oil price. Production growth even accelerated in 2001, despite a drop in prices that year. Clearly, rising oil prices gave the sector a tremendous opportunity, but they do not appear to have triggered the recovery. Nor, more recently, have record oil prices been sufficient to enable rapid growth rates to be sustained in the face of adverse developments with respect to state policy towards the sector.

29. The stark contrast in the relative performance of private and state-owned companies suggests that these undoubtedly impressive results owe a great deal to the decision to privatise – an impression that is reinforced by the contrast between Russia’s oil industry and its gas sector. Dominated by the state-controlled, vertically integrated monopoly OAO Gazprom, the gas industry is arguably Russia’s least-reformed major sector and undoubtedly one of its least efficient.⁵⁸ By 2003, its unit labour costs were more than double the levels of 1997: in a sector where wages were already four times the all-industry average *before* the crisis, they rose much faster than for non-gas industry afterwards, despite a drop of around 20% in labour productivity – a truly spectacular underperformance. While industrial output rose by almost 40% in 2000–04 and crude oil output rose by 50%, gas production more or less stagnated. The Economic Expert Group attached to the Ministry of Finance estimates that the gas industry’s overall contribution to GDP growth during 1999–2004 was actually slightly *negative*.⁵⁹ The gas sector’s poor performance is an extreme example, but not an isolated one: output and productivity in Russia have generally grown faster in

57. See OECD (2004), Chapter 1 and Ahrend (2006).

58. See Ahrend and Thompson (2004) for details.

59. Gurvich (2004, 2005). This might seem a surprising conclusion at first sight, since gas output rose slightly from 1999 to 2004. However, Gurvich assesses the sector’s contribution to *value added* (as opposed to output), which appears to have been negative.

sectors that were relatively free of state ownership and interference. Moreover, in sectors where private and state-controlled companies operate side by side, private companies have generally been more efficient.⁶⁰

30. Nevertheless, the oil sector's successes should not obscure the very real problems created by the policies of the 1990s. Both the perceived insecurity of property rights and the nature of the tax regime served to discourage long-term investment, as did the overall instability of the regulatory and fiscal framework. While investment did recover strongly after 1998, most oil sector investment has been aimed at increasing current production rather than developing new fields. It is not at all clear that the existing tax regime will be attractive when it comes to making large, up-front investments in the development of new fields. There are, indeed, good reasons to believe that it will not (Annex 2). Of course, the recent focus on investment in existing fields is hardly surprising in response to a rapidly rising spot price: the priority for companies has been to pump oil and get it to market while prices remain high. That said, investment patterns do suggest that doubts about the security of property rights are also having a distorting effect on capital expenditure. Companies controlled by the *finansisty*, whose property rights have tended to be seen as less secure than those of the *neftyaniki*, have also been significantly less inclined than the *neftyanik*-controlled companies to undertake long-term investment.⁶¹ They have focused much more on maximising current production and exports – precisely the behaviour one would expect of agents whose property rights were relatively insecure.⁶² This has prompted critics to claim that the *finansisty* have been extracting (and exporting) too much oil at the expense of long-term development. The question of over-extraction is hotly contested – engineers and oil-services companies working with the *finansist*-controlled companies insist that West Siberia's recoverable reserves are far greater than previously realised and that, with the aid of new technology, they have *improved* reservoir management. Either way, there is no doubt that these companies have been less inclined than their rivals to invest in projects with long payback times.⁶³

31. Short time horizons have also been one of the major factors behind the low level of exploration activity. Three other factors are also at work. The first is that the companies and the state now assess reserves differently (Annex 1). By international standards, Russian oil companies are very well endowed with reserves and have done very well at growing them in recent years. Most of them thus feel no urgent pressure to undertake a great deal of new exploration. The state, by contrast, relies on a different set of reserves definitions and is chiefly concerned with the discovery of new resources in the ground, which have fallen far short of production-replacement levels.⁶⁴ The second factor at work is the regulatory framework, which fails to create any real incentives for companies to explore: there is still no guarantee that a company making a commercially significant discovery will have the right to develop the deposit – or

60. See OECD (2004:42–4 and 125–7).

61. See OECD (2004:42–4); Dienes (2004); and Gaddy and Ickes (2005). In hindsight, the former owners of Yukos, at least, appear to have been well advised to focus on investments with short payback periods.

62. Dienes (2004) attributes the *finansist*-controlled companies' focus on current production to their determination to maximise their market capitalisation. However, Gaddy (2004:349–50) rightly observes that oil companies' stock market valuations in the West are not by any means a function of current production alone – indeed, reserves data are so important that companies have been known to fudge them in order to please the market. The short-term focus of the *finansisty* is easier to understand as a function of insecure property rights than as a response to capitalist incentives.

63. See Gaddy and Ickes (2005:13–14). In general, if an individual's claim to the future return of a resource stock he currently controls is insecure, he has an incentive to maximise his immediate gains by extracting more in the short term than an optimal long-term extraction path would warrant.

64. As noted above, the official reserve estimates are a state secret. However, the authorities have stated that only 70% of reserves were replaced in 2002, 60% in 2003 and 72% in 2004. Rates of well above 100% are needed if Russia hopes not only to sustain production but to sustain production growth.

even to be compensated for its troubles. In any case, conflicts within the administration over resource-management policies have meant that the government has been very slow to conduct tenders for exploration licences, even with respect to areas that it regards as high priorities, such as East Siberia.⁶⁵ Thus, such exploration as the oil companies do undertake tends to be concentrated near fields where they already hold licences and control the infrastructure. This ensures that they are well placed to press their claims to any subsequent development. The authorities are committed to rectifying this problem in a new law on subsoil resources, but its adoption has been subject to repeated delays.⁶⁶

32. The third factor at work is the tax system, which provides little incentive to undertake exploration or investment in new fields with long payback times. There are a number of problems here. Recent attention has focused on the very high marginal tax rates applied to the sector: the state now collects just close to \$0.90 per barrel exported for each one-dollar rise in the international price above \$25/bbl.⁶⁷ Certainly, this reduces the ability of Russian oil producers to finance investment from retained earnings, but at current oil prices most Russian producers are still generating extremely large profits,⁶⁸ and there are good reasons for the state to want to capture the bulk of the windfalls arising from exceptionally high prices.⁶⁹ Besides, the size of the state's take will decline as and when oil prices fall. Indeed, at lower oil prices, the oil sector's effective tax burden is not particularly heavy compared with that of other sectors (Annex 2).

33. The much more serious problem with the tax system is the continuing reliance on taxes that are focused on physical volumes and revenues rather than profit, particularly the mineral resource extraction tax (NDPI).⁷⁰ This emphasis on volume and revenue is intended to counter transfer pricing in the sector, which previously made tax evasion possible on a truly spectacular scale. The introduction of the new mineral resource extraction tax in 2002 gave the government a relatively effective means of curtailing the use of transfer pricing for purposes of tax evasion. However, the reliance on profit-insensitive taxes can render production from higher-cost fields unprofitable even at relatively high prices and thus reduce substantially the number of fields that it makes commercial sense to exploit. This is a particularly serious problem, given that a growing proportion of reserves still to be developed are in smaller, more difficult fields and that extending the lives of declining fields already in production is also critical if output growth is to be sustained. In many cases, too, the current structure of taxation can lead to actual effective tax rates on domestic crude sales that are both higher and more volatile than they appear – and that vary widely

65. IEA (2005a:6–7).

66. In early November 2005, the government again asked the State Duma to postpone the first reading of this crucial bill, which had initially been introduced into the chamber in June of that year.

67. The marginal revenue from the mineral extraction tax and the crude oil export duty amounts to \$0.87 per dollar on the price, with the state collecting almost one-quarter of the remainder via the profit tax, assuming no 'tax optimisation' strategies are employed to evade the latter. The Economic Expert Group attached to the Ministry of Finance estimates the actual marginal tax rate per dollar on the Urals price at 85%, owing to three factors: some exports are exempt from the duty; compliance is less than 100% in any case; and some crude can be shifted from export to refineries, as duties on refined products are far lower. In addition, rising domestic prices bring producers an estimated \$0.08 per barrel on domestic sales for each dollar rise in the export price.

68. The Federal Agency for State Statistics estimates that pre-tax profits from oil extraction jumped 88% year on year during January-July 2005, an estimate that broadly corresponds to investment bank estimates of the profitability of the major companies. See *Vedomosti*, 26 September 2005.

69. See OECD (2004), ch. 1 on the rationale for heavier taxation of natural resource sectors (not only oil) and the pitfalls involved.

70. See Annex 1 for a detailed examination of the structure of oil-sector taxation.

from company to company. The authorities are well aware of these problems and some revision of the NDPI regime is likely to be adopted this year, to take effect in 2007 (Annex 2). Finally, constant tinkering with the tax system has meant that, whatever its merits or defects, it has failed to provide investors with any kind of stable basis for medium- or long-term planning.

34. To the insecurity of property rights arising from flawed privatisation and the weakness of the rule of law must be added the uncertainties arising from the licensing regime. Licences to exploit subsoil resources are notoriously complex, and there is considerable scope for bureaucratic arbitrariness in administering them. Under the current law on the subsoil, licences can be revoked if the licensee fails to fulfil any ‘significant terms’ of the agreement, but the law fails to specify what a significant term might be. While actual revocation has been relatively rare, the threat of licence withdrawal has often been used to pressure companies. Companies do not in any legal sense *own* their licences. However, insecure licences have many of the same effects as shaky property rights, not least because subsoil licences are often the most valuable assets that Russian companies have – even if they do not legally *own* them.⁷¹ The government is officially committed to the transition from a licensing regime to one based on civil law agreements (*i.e.* concessions), which could offer investors greater transparency, predictability and security of tenure and would also facilitate the circulation of resource-exploitation rights among market players. Greater security, more over, would reduce the incentives to over-produce in the short term at the expense of a field’s long-term potential: the less secure investors feel with respect to property rights or licences, the greater their incentive to profit as much as possible in the near term, regardless of the long-term costs. However, the adoption of the new law on the subsoil has been subject to repeated delays, and the bill prepared for consideration by the State Duma in early 2005 was so poorly drafted that it threatened to reduce, rather than enhance, investor protection and the security of property rights.⁷² By early 2006, the indications were that adoption of an entirely new law was to be postponed for 2–3 years and that a package of amendments to the old subsoil law would be passed in its stead, in order to make the most urgent changes promptly while leaving time for further work on the law as a whole.

35. A final problem concerns the larger relationship between the privatised companies and the state. There have been a number of points of conflict. The authorities grew increasingly impatient with the aggressive ‘tax optimisation’ strategies of some of the VICs, which involved transfer pricing on a massive scale, the use of ‘internal offshore zones’ in parts of the Russian Federation and other such stratagems.⁷³ The authorities were also irritated by the power of the oil lobby to thwart tax changes and other policy initiatives desired by the government and by the fairly brazen manner in which some companies solicited support from parliamentarians and other politicians.⁷⁴ The companies, for their part, resented the state’s continuing drive to secure a larger share of oil rents and were increasingly frustrated by what they perceived as the failure of the authorities either to press ahead with the infrastructure investments they desired or to allow the companies to make such investments themselves. There was particular conflict over proposed pipeline projects to Murmansk and to China backed by Yukos and, in the case of Murmansk, by other major Russian oil companies as well.

71. The implications are clear: if one buys a company primarily to secure its licences, then the security of those licences will be a crucial determinant of the price one can pay.

72. See Skyner (2005) for a close analysis of the draft text. On the whole, the problem was less what was in the text than what was omitted: numerous crucial issues were left to the discretion of bureaucrats in the relevant ministries.

73. The now dismembered Yukos has become the company best known for such strategies, but a comparison of effective tax rates by company suggests that it was not as aggressive in its ‘optimisation’ as was Sibneft.

74. These include, in some cases, claims that oil lobbyists distributed cash directly to Duma deputies following major votes.

36. The backdrop to these and other conflicts may well have been as important as the points of friction themselves. On the one hand, the property rights of the VICs' owners (and, in particular, of the *finansisty*) were widely seen as illegitimate and were thus not fully secure. On the other hand, the state found these powerful, private companies increasingly difficult to 'manage' in view of its own limited administrative and regulatory capacities. Indeed, one reason for the state's determined opposition to private pipelines appears to be that the authorities regard Transneft as a crucial lever in managing the 'oil barons'. Some government officials and Transneft executives have even suggested that export infrastructure might be used to *constrain* production growth, so as to prevent what they believe to be over-production at the expense of long-term recoverability and to conserve Russia's oil reserves for future generations.⁷⁵

Azerbaijan and Kazakhstan

37. At the beginning of the transition, the two most promising Caspian producers, Azerbaijan and Kazakhstan, faced a rather different set of challenges to those confronting Russia and they thus opted for a rather different approach. Both states badly needed foreign capital and technology to develop their hydrocarbon resources and, in the immediate post-Soviet period, they were inclined to welcome a high degree of western – as opposed to Russian – involvement, for both political and commercial reasons. Subsequently, they also developed increasingly close commercial links to Russia, with Lukoil, in particular, becoming active in both markets.

38. The newly independent *Azerbaijan* inherited a mature oil industry – Azerbaijan had indeed been the cradle of the oil industry in imperial Russia⁷⁶ – but its onshore fields were in decline and it required substantial new investment in order to develop large-scale new projects off shore and to refurbish existing fields. While maintaining full state ownership over energy companies, Azerbaijan was quick to invite foreign investors to assume a direct role in the development of its hydrocarbon reserves. Most of the state's existing oil-sector assets were consolidated in September 1992 with the merger of two state oil companies, Azerineft and Azneftkimiya, into the State Oil Company of the Azerbaijan Republic (SOCAR). SOCAR and its many subsidiaries are responsible for the production of oil and natural gas in Azerbaijan, for operation of the country's two refineries and its pipeline system, and for managing the oil and natural gas imports and exports. While government ministries handle exploration and production agreements with foreign companies, SOCAR is party to all the international consortia developing new oil and gas projects in Azerbaijan. SOCAR was created precisely for that purpose – to attract foreign players without compromising state control. The company accounts for around 60% of total oil output in Azerbaijan.

39. Azerbaijan has arguably been the most consistently accommodating CIS state in its dealings with foreign investors, relying more than its neighbours on project-specific arrangements tailored to meet investor/state needs – major deals have virtually all been done on a PSA basis.⁷⁷ The fiscal framework, in particular, reflects this approach. There are currently four separate and distinct tax regimes applicable to oil-sector activities in Azerbaijan. The statutory regime (royalty, excises and generally applicable taxes) is actually relatively unimportant. The largest (and growing) share of oil production is covered by the alternative tax regimes applicable to companies operating under PSAs.⁷⁸ There are also specific tax

75. Gorst (2004:8–9).

76. Peak production to date was around 500kbd, achieved during the Second World War.

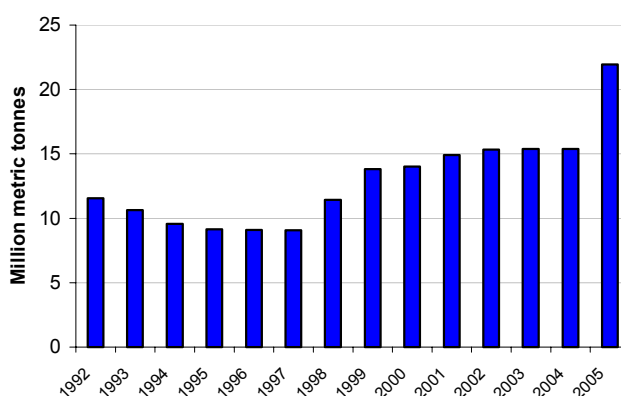
77. In 2000, Azerbaijan decided to abolish joint ventures and convert them to the more investor friendly PSAs in an effort to spur increased development.

78. The PSA regime is a description of the rules covering the twenty-two production sharing agreements ratified by the Milli Majlis and generally applies to all contractor parties in PSAs and their direct and indirect foreign subcontractors.

regimes for companies working on the South Caucasus Pipeline and the Baku-Tbilisi-Ceyhan (BTC) export pipeline. The latter, which began operating in May 2005, avoids both Russia and the Turkish straits, taking Azeri crude to a terminal on the Turkish Mediterranean coast (see Annex 3).

40. As a result of Azerbaijan's investor-friendly approach, an influx of foreign investment since independence has revitalized the country's oil sector. To date, Azerbaijan has signed over 20 major field agreements with approximately 30 companies from 15 countries. Between 1995 and 2004 Azerbaijan attracted more than \$11bn in foreign investment, as much as 90% of which was directed into its oil and gas sector. Crude oil output rose by just over 80%, from a post-Soviet low of 180kbpd in 1996 to 327kbpd in 2003 (Fig. 6).⁷⁹ Production fell slightly in 2004, owing to technical problems and planned maintenance in the main offshore fields, but with new fields raising production to fill the BTC pipeline, which began operations in the spring of 2005, oil production soared. Preliminary official data indicate that oil output rose by 42.5% in 2005 to 445kbpd, with exports rising by 48%.

Figure 6. Crude oil and NGL production in Azerbaijan



Source : IEA, Oil Information 2005 Database

41. Crude production growth since 1997 has mainly come from the international consortium known as the Azerbaijan International Operating Company (AIOC).⁸⁰ The AIOC operates the offshore Azeri Chirag and deep water Gunashli (ACG) mega-structure, which is estimated to contain proven crude oil reserves of 5.4bn bbl. The field reached an average daily output of 144kbpd in June 2004, mostly from the Chirag-1 stationary platform. Azerbaijan's main production surge in the next decade is expected to come from the three-phase development of the ACG mega-structure. ACG production is slated to reach approximately 500kbpd by 2007, rising to roughly 1mbpd by 2009. Azerbaijan could be exporting 1.1mbpd by 2010, as compared with roughly 211kbpd in 2004.⁸¹ The AIOC is currently investigating plans for a third phase, beyond 2009, which will complete full field development.

42. Not all foreign investment projects have been so successful, however. Several have announced disappointing drilling results in recent years, and a number of joint ventures and PSAs have shut down

79. This is well below the 500kbpd peak recorded during the Second World War in Azerbaijan, but above the level of 286kbpd recorded in 1987.

80. In addition to SOCAR, the AIOC consortium includes BP, Unocal, Inpex, Statoil, ExxonMobil, TPAO, Devon Energy, Itochu and Delta/Hess.

81. The government expects to reach this level by 2008.

after failing to find the anticipated volumes of commercially recoverable reserves.⁸² Indeed, there has been only one major new discovery since the 1994 agreement with the AIOC was signed. While production from the ACG structure is set to grow rapidly between now and 2010, it is also expected to have a relatively brief production plateau. The World Bank (2005a) thus estimates that, in the absence of substantial new discoveries, Azerbaijan's oil production will peak in 2010 at about 1.5mbd before going into decline.

43. The existence of *Kazakhstan's* considerable hydrocarbon resources was well known in Soviet times, but the Soviet authorities were slow to develop them, preferring (in part for political and security reasons) to give priority to the development of Western Siberia. Soviet-era production nevertheless reached a peak of 569kbd by 1991. The Kazakh government quickly recognised the need for foreign capital and expertise, in view of the relatively under-developed state of its most important deposits, the technical problems posed by some of those developments and the desire to reduce the country's reliance on Russia. It began courting foreign investors more or less immediately after independence. Indeed, given the severity of the immediate post-Soviet economic crisis, the immaturity of its oil industry and the lack of any other sector capable of generating substantial foreign exchange earnings quickly, the Kazakh authorities deliberately tried to secure deals with foreign investors to develop the country's largest fields first.⁸³

44. Like Azerbaijan (and unlike Russia), Kazakhstan opted to rely heavily on tax and regulatory packages tailored to meet the needs of investors in large projects, whether in the context of PSAs, joint ventures or concessions. Some projects combine elements of more than one of these forms. Two types of contract between subsurface users and the state were employed: PSAs (referred to in tax legislation as a Model 2 tax regime), and a 'Model 1' contract – essentially an excess-profits tax (EPT) model – that envisages the payment by a subsurface user of all taxes and other obligatory payments that would generally apply to a taxpayer.⁸⁴ The Tengiz field, which is being developed by the ChevronTexaco-led Tengizchevroil venture, is the most important project operating under a model 1 contract; most other major deals have involved PSAs.

45. One important difference between Kazakhstan and Azerbaijan has been the greater willingness of the latter to operate on a case-by-case basis. While PSAs and concessions are negotiated as a matter of course in Kazakhstan – unlike Russia, where they are still exceptional – Kazakh contracts over time have come to be based increasingly on a body of law applicable to all projects. For investors in the 1990s, this was not a major impediment. The crucial factor was the readiness of Kazakhstan to conclude both PSAs and 'Model 1' contracts that would protect them from subsequent changes in taxation or other policies. The tax regime was to be stable for the life of the contract. The question of contract sanctity and stability was central to Kazakhstan's drive to attract foreign investors. As will be seen below, it has more recently become the focus of conflicts between the state and foreign companies.

46. Unlike Azerbaijan (and like Russia), Kazakhstan also opted to privatise most of its existing oil and gas enterprises – mainly to foreign owners and often with significant social commitments included in

82. This refers primarily to oil. Azerbaijan has lately enjoyed more success in finding new gas deposits.

83. Jones Luong and Weinthal (2001).

84. From a tax perspective, PSAs differ from regular subsurface use contracts in that under PSAs, the government, without investment, receives a direct share of the field's production, in cash or in kind. The costs of the subsurface user are recovered from production in priority (subject to limitations) to the state's share. This means that the subsurface user, at his own risk, is expected to pay all initial exploration and development costs for the contract area and subsequently to recover the costs of carrying the government's interest in the contract area from the total production. Note that, technically, the state's share is a tax.

the terms of the sales.⁸⁵ Numerous small, on-shore fields were also taken over by private companies under various contracts. Many of these private companies were controlled by interests close to the government or the state-owned companies involved, raising questions about the terms of these transactions, but the production performance of the small on-shore privates was generally good. The pipeline network constituted the major exception to the authorities' readiness to privatise – while Kazakhstan has been readier than Russia to accept the construction of new private pipelines, the network inherited from Soviet times has remained in state ownership, which may well make sense in view of its natural monopoly character.

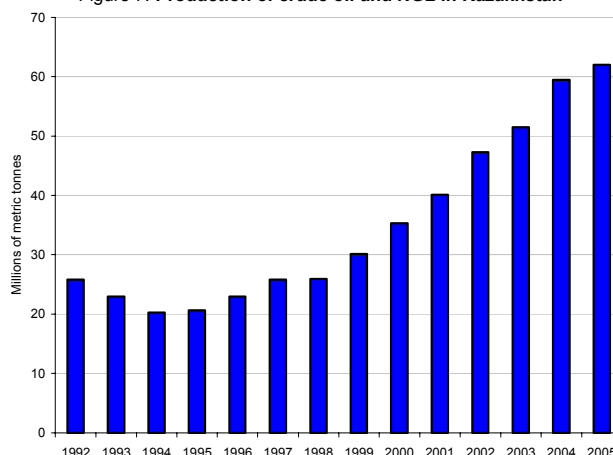
47. The Kazakh approach was extremely successful in attracting western capital to the oil sector. Indeed, the country became the largest recipient of foreign direct investment (FDI) *per capita* in the CIS. During 2001–05, net FDI inflows averaged around 10% of GDP, as compared with levels of 1.5–2.5% in Russia. By end-2004, the cumulative stock of FDI in oil and gas extraction had reached around \$16bn.⁸⁶ The first big projects involving foreign capital included the development of the Tengiz field, located in the swamplands along the northeast shores of the Caspian Sea. Rights to develop another large on-shore field, Karachaganak, were awarded to the Karachaganak Integrated Organisation, led by BG and AGIP, in June 1993. By 2005, oil and gas fields in Kazakhstan were being explored and developed in the framework of 27 international projects (though in some cases the 'foreign' companies involved are ultimately controlled by Kazakh interests). At least \$30bn is expected to be invested in Kazakhstan's oil sector by 2015. The most significant single project is the Kashagan offshore field in the Caspian, which contains an estimated 7–9bn bbl in recoverable reserves (up to 38bn probable on some estimates) and which is being developed by a consortium led by Eni, Total, ExxonMobil and Shell. The development of Kashagan alone is expected to absorb \$20bn, of which \$8bn is to be spent before the first oil is produced in 2008. Output from Kashagan is expected to rise sharply to 2018 and then more slowly to 2030, reaching a plateau of around 50–60mt per annum for an extended period; the field could be exploitable for 70–80 years.

48. As successive projects have come on stream, Kazakhstan's crude oil production has soared (Fig. 7), reaching approximately 1.22mbd in 2004 – roughly triple the post-Soviet low of 414.8kbd recorded in 1995. Most of this growth occurred towards the end of the period, as production grew at an average annual rate of just under 16% during 1999–2004. With domestic consumption of just 224kbd, the country generated net exports of almost 1mbd, rising to 1.1mbd during 2005. The government hopes to increase production levels to around 3.5mbd by 2015, a target that appears entirely feasible on the basis of projects already under way. This would include approximately 1mbd from Kashagan, 700kbd from Tengiz, 600kbd from Kurmangazy and 500kbd from Karachaganak. Other smaller fields would account for the balance. Some western oil executives believe that Kazakhstan could reach 4mbd if the authorities wish to do so and are prepared to offer more attractive fiscal terms to investors interested in developing the remaining North Caspian blocs. As will be seen, however, there are questions as to whether or not the authorities really want even faster output growth, given the problems this could create for macroeconomic management. Indeed, some recent developments raise doubts as to whether or not Kazakhstan will even achieve the 3.5mbd target by the middle of the next decade.

85. During 1996–97, the government sold off the Chymkent Oil Refinery, Yuzhneftegaz, Mangistaumunaigaz, Aktyubinskneft and the Uzen oil fields.

86. Unlike Azerbaijan, moreover, Kazakhstan has been relatively successful in attracting FDI to other sectors – the total stock of FDI is estimated to have reached \$29.75bn by the end of the third quarter of 2004.

Figure 7. Production of crude oil and NGL in Kazakhstan



Source: IEA, Oil Information 2005 Database

49. While the oil and gas enterprises inherited from the USSR were largely privatised in the mid-1990s, the authorities created a national oil and gas company, Kazakhoil, in 1997 to manage the state's remaining oil-sector enterprises and its interest in PSAs, which had until then been held by the Ministry of Energy and Mineral Resources. In February 2002, the consolidation of state assets went a step further with the creation of a vertically-integrated state oil and gas company, Kazmunaigaz, via the merging of Kazakhoil and Transneftegaz. The latter was a state-owned oil and gas transport group made up of KazTransOil and KazTransGaz, the two companies that operated the country's trunk pipelines. The purpose of this integration was to ensure a united and coherent state policy on using the country's hydrocarbon resources. Kazmunaigaz was also given the task of overseeing a major licensing round, which began in 2003, involving over 100 blocks in the Kazakh sector of the Caspian shelf. Kazakhstan is also looking for Kazmunaigaz to compete with foreign energy companies.

50. While many observers welcomed the creation of Kazakhoil and later of Kazmunaigaz, one of its main purposes – to clarify the division between the state's commercial and regulatory roles – has never been fully realised. Ostensibly, the oil professionals of Kazakhoil (later Kazmunaigaz) were to manage the state interest in all arrangements with foreign partners, including the Caspian Pipeline Consortium (CPC), from exploration and exploitation to royalties, while the Ministry of Energy and Natural Resources was to have a purely regulatory role. Yet Kazmunaigaz itself has continued to combine commercial activity with a significant regulatory role in fields ranging from oil and gas transport to export access to licensing. The state's ambitions for Kazmunaigaz have recently been the source of some irritation to investors (see below).

51. Both Azerbaijan and Kazakhstan have made considerable progress in resolving the problem of access to export markets, which was very acute in view of their landlocked location, their initial dependence on evacuation routes running through Russia and the geopolitical difficulties posed by many of the possible alternatives (see Annex 3 for details). Geography and commercial expedience alike point to the desirability of a direct route to the Gulf via Iran, but financing such a route would be extremely difficult given Iran's international position, while routes through Transcaucasia and/or Afghanistan would be exposed to high levels of political risk, and any route taking yet more Caspian crude to the Black Sea merely aggravates the increasingly tight bottleneck of the Turkish straits. Both Caspian producers are thus likely to export to the Mediterranean through the BTC pipeline running from Baku, while Kazakhstan is developing export routes to China and expanding its existing routes through Russia, relying on both the Transneft system and the CPC.

52. Nevertheless, there are concerns that, even if all the infrastructure plans now in train are realised, there will be insufficient capacity to handle all of Kazakhstan's crude. Export infrastructure constraints could yet prove a significant impediment to output growth. Moreover, Kazakh export routes through Russia are still subject to a degree of uncertainty. Russia held up the planned expansion of the CPC pipeline for several years, finally agreeing to proceed only in October 2005. The following month, Russian pipeline monopolist Transneft withdrew from an agreement with Kazmunaigaz concerning the transport of 12mt of Kazakh crude to Lithuania over a 10-year period. Transneft's action threw into question Kazmunaigaz's bid for the Yukos-owned Mazeikiu nafta refinery in Lithuania.⁸⁷ Transneft has blamed Kazmunaigaz for the disruption, saying that the latter had failed to secure the necessary changes in the inter-governmental agreement on oil transit, but the timing of Transneft's withdrawal from the agreement suggests it may have been intended to influence the outcome of the Mazeikiu nafta sale.⁸⁸ The dispute over the Mazeikiu transport agreement is merely the latest illustration of why *ratification of the Energy Charter Treaty and adoption of its transit protocols by all the states in the region – and particularly by Russia, which remains the key transit state for the other CIS producers – are needed.*

Uzbekistan and Turkmenistan

53. The two minor CIS producers, Uzbekistan and Turkmenistan, opted for a third path, combining continued state ownership with little or no foreign involvement. There is probably more behind this choice than mere ideology. Jones, Luong and Weinthal (2001) note that these two states were under less pressure than Azerbaijan or Kazakhstan to privatise or to accede to the demands of foreign investors. Their leaders faced no serious domestic pressure to privatise, and the presence of alternative sources of export earnings (cotton) meant that developing their hydrocarbon sectors was not such an urgent priority as it was in Azerbaijan and Kazakhstan. While the political rationales for various development strategies are not the focus of this paper, they are important to understand, because factors such as these will continue to shape the policy choices made in future.

54. At first glance, the experiences of these two states might not appear to matter much. They are, after all, relatively marginal producers at present (Fig. 8) – in 2004, Uzbekistan produced around 152kbd and Turkmenistan 202kbd – and neither shows any sign of raising production in the coming years in the way that Azerbaijan seems set to do. Turkmenistan, however, may have much greater potential as an oil producer than is generally recognised. While it is primarily known as a gas producer,⁸⁹ Turkmenistan is widely reckoned to be under-explored and is estimated by USGS (2000) to have exceptional promise with respect to as yet undiscovered oil reserves. While the country's proven reserves are currently estimated at around 500m barrels,⁹⁰ the USGS mean probability estimate for undiscovered oil is 6.8bn, with the low (5%) and high (95%) probability estimates being 13.4bn and 1.8bn respectively. Given that larger volumes

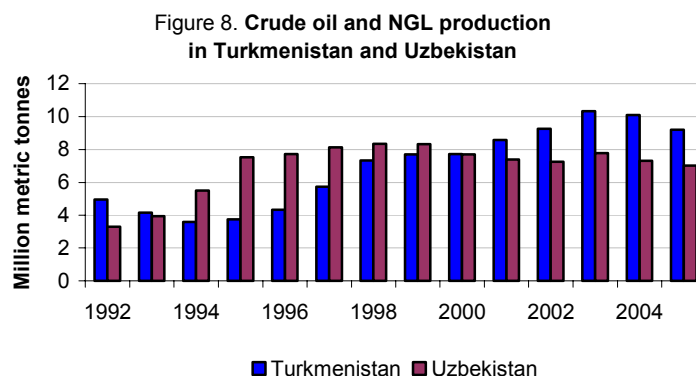
87. *Vedomosti*, 18 November 2005.

88. The sale has yet to take place as of this writing. Kazmunaigaz insists it still wishes to buy the refinery and the Kazakh government is pressing Moscow to force Transneft to honour the transit agreement.

89. Uzbekistan, too, looms much larger as a gas producer: it has proven reserves of 1.88 trillion cubic metres of natural gas and in 2003 produced 58bcm. Uzbekistan is the third largest natural gas producer in the Commonwealth of Independent States and one of the top ten natural gas-producing countries in the world.

90. Here, as elsewhere, reserves estimates are taken from BP (2005) unless otherwise indicated. However, it should be noted that the Uzbek and Turkmen authorities do not issue regular revisions to reserves, and these estimates have remained unchanged for some years.

of oil have been located all around the Caspian basin, it is hardly surprising that Turkmenistan is reckoned to be so promising.⁹¹



Source : IEA, Oil Information 2005 Database

55. Unlike Azerbaijan, which retained state ownership of hydrocarbon deposits but was content to allow foreign investors a leading role in developing them, *Uzbekistan* has been reluctant to cede much control to outsiders. Rather than privatising enterprises, or putting fields up to tender, Uzbekistan has tended to prefer loan-financed projects and contracts with foreign services companies. The country borrowed at least \$1bn in the 1990s in an effort to achieve self-sufficiency in oil and gas. In 1992, a national Uzbek oil and gas company, Uzbekneftegaz, was established by merging the existing enterprises in charge of upstream activities, oil refining and product distribution, gas transmission and distribution, and petroleum facility construction. Later, Uzbekneftegaz also took over enterprises responsible for petroleum exploration, which had previously reported to the Uzbek Committee on Geology.

56. Foreign oil and gas companies contributed little to the development of Uzbekistan's petroleum resources during the 1990s: only Malaysia's Probady secured exploration and production rights and was carrying out field development work. Lukoil formed a JV with Uzbekneftegaz to develop some fields. Enron, Texaco, Pertamina and Unocal signed letters of intent with the Uzbek company at various times, but they faced long delays in dealing with a government that was clearly unenthusiastic about foreign involvement in the sector, and little concrete work was actually undertaken. Uzbekneftegaz signed its first PSA in April 2001, with Britain's Trinity Energy, through a specially formed subsidiary known as UzPEC Ltd.⁹² In 2004, control of UzPEC passed from Trinity Energy to the Moscow-based Soyuzneftegaz, and in February 2005, the Uzbek government launched an investigation to determine whether UzPEC had properly fulfilled the licence conditions for the fields. Uzbekneftegaz declared its intention to break the PSA, and in mid-2005, the government indicated that it was minded to withdraw UzPEC's licences. UzPEC and its new owners, Soyuzneftegaz, contested these decisions, but tensions between the partners reportedly put development of the fields on hold throughout 2005.

91. The corresponding figures for Uzbekistan are much lower – the USGS mean probability estimate is 140m barrels, and the upper and lower estimates are just 43m and 276m respectively, as compared with known reserves of around 600m barrels.

92. The project entailed the development of fields in Uzbekistan's central Ustyurt and Southwest Gissar regions, with the partners forecasting natural gas production of roughly 2bcm and oil production of 2.6kbbd by 2006.

57. For a time, at least, Uzbekistan could argue that its formula had prevented disruption to the sector and thus ensured continuity of supply: production grew rapidly during the 1990s, rising from 69kbd at the end of the Soviet period to a peak of 191kbd in 1998–99. This enabled the country to achieve rough self-sufficiency in oil, an important goal of the Uzbek authorities. However, domestic regulation of the market meant that the hydrocarbon sector suffered from considerable distortions and inefficiencies – artificially low domestic prices for crude and refined products generated substantial smuggling of oil and products to neighbouring Kazakhstan.⁹³ Moreover, the production levels reached in the late 1990s soon proved unsustainable. Output fell by more than 20% during 2000–2004, and preliminary estimates point to a further 17% decline in 2005. As no significant new discoveries have been reported, there are questions about Uzbekistan’s ability to sustain its self-sufficiency in oil, at least in the absence of outside assistance.

58. Indeed, poor recent performance appears to have prompted the Uzbek authorities to reconsider their approach to the hydrocarbons sector:

- There are plans to privatise a minority stake in Uzbekneftegaz. However, it remains to be seen whether private investors will be keen to acquire shares in the company while the state retains majority control. It may well end up in the hands of a state-owned company from one of the major consuming countries, most likely China.
- The authorities have signed a number of agreements with Chinese and Russian companies concerning investment in the sector. Lukoil and Gazprom are set to invest at least \$1bn in Uzbekistan’s hydrocarbons sector (including the pipeline network) under PSAs signed in November 2004. These deals are chiefly concerned with gas and condensate production, but a May 2005 agreement with China’s CNPC envisages the creation of a joint venture, UzCNPC, that will bring together Uzbekneftegaz and CNPC to explore and develop fields in the Bukhara-Khiva region and on the Ustyurt plateau over a 25-year period. Malaysia’s Petronas hopes to reach agreement by the end of the year on a joint venture with Uzbekneftegaz to develop oil and gas deposits in the Aral Sea basin.
- There are also plans to borrow from the Chinese government and the Chinese company Sinopec to modernise the pipeline network and to rehabilitate exhausted oilfields over the next five years.

59. The authorities in *Turkmenistan* have adopted an even more autarkic, *dirigiste* approach than those in Uzbekistan. In managing its hydrocarbon resources, as well as other sectors of the economy, Turkmenistan has pursued, in some respects, a quasi-Soviet approach to economic policy throughout the post-independence period. The Turkmen system continues to be characterised by the predominance of state ownership of the means of production, restrictions on foreign exchange activities, widespread subsidies (including the free provision of utilities) and an approach to ‘planned’ development on the basis of import-substituting industrialisation. While some privatisation has taken place, the authorities remain explicitly committed to maintaining the major productive sectors in state hands.

60. This has not prevented Turkmenistan from making some efforts to attract foreign investors to its hydrocarbons sectors – it has recently been particularly concerned to bring them into oil production and petroleum refining, in an effort to reduce its dependence on gas exports. On paper, at least, the country has made considerable progress. IEA (2002b) observes that its model PSA looks workable and avoids the sort of *ad hoc* arrangements some other states have reached with investors. Both the model PSA and the model

93. These appear to have been partially offset by smuggling from Turkmenistan, where prices are lower still. The situation in the gas sector in Uzbekistan is similar, since Uzbekneftegaz has to supply gas at tariffs that are well below cost-recovery levels, payment discipline is sometimes patchy, and there is a great deal of cross-subsidy from industry to households.

joint venture agreement adopted by Turkmenistan promise investors long-term stability of tax and regulatory conditions. There are explicit restrictions on foreign participation – the model JV agreement limits the foreign stake in a JV to 10–30%, unless ‘extraordinarily’ large sums are spent on exploration, and both model agreements exclude foreign participation in projects in previously explored territories. They do, however, grant investors a monopoly on oil-related activities in the contract area.

61. In practice, Turkmenistan has proved an extremely difficult place in which to do business and has attracted little foreign investment. Arbitrary state action, high levels of corruption, poor infrastructure and a lack of export routes, together with the general unattractiveness of the heavily regulated business environment, have combined to deter investors. Another factor has probably been Turkmenistan’s refusal to sign up to the agreement on dividing the Caspian Sea, which has stalled any significant offshore development. This is a particularly significant opportunity foregone, given that 40% of its proven reserves are reckoned to be offshore. Its proven reserves in any case appear to be considerably smaller than those of Azerbaijan and Kazakhstan,⁹⁴ so most major international players have preferred to concentrate on those two countries, both of which are seen as more attractive business locations.

62. It is thus hardly surprising that Turkmenistan has so far concluded only smaller-scale deals with outside investors – cumulative FDI is estimated at only about \$1.6bn as of end-2004 – and these have not always been handled in such a manner as to encourage others. In 1996, Argentina’s Bidas took legal action against the government for having revoked its oil export licence, forcing the company to sell crude at a loss to a local refinery. The Turkmen authorities claimed that Bidas had taken advantage of Turkmen negotiators’ lack of experience during the early post-independence period in order to negotiate an agreement that was unreasonably favourable to the company, which Bidas then subsequently refused to renegotiate. Larmag and Dragon, two other early entrants, were also put under pressure as the government decided it had made too many concessions during initial negotiations. These companies agreed to a revision of terms. Nevertheless, Turkmenistan currently has five active PSAs in the oil sector, all on a relatively modest scale.⁹⁵ The authorities have for several years been involved in negotiations with the Russian Zarit consortium concerning an oil-sector PSA to explore the Turkmen section of the Caspian. The consortium comprises two state-owned Russian companies, Rosneft and Zarubezhneft, as well as the privately owned Itera. The PSA was to have been signed in January 2004 but has been repeatedly postponed. International service giant Schlumberger is also involved in Turkmenistan, and a well-rehabilitation contract was signed with China’s CNPC in 2001.

63. In terms of output, Turkmenistan’s record in the early 1990s was relatively good. Its resistance to structural reform and its readiness to invest heavily in raising oil output meant that it weathered the early transition better than some other CIS states and, after an initial fall in output, managed to increase crude

94. The scale of the country’s reserves are difficult to judge, owing to the state’s concern with secrecy. It is known that an international audit of its onshore gas reserves has been done, but the results have not been made public. Whatever Turkmenistan’s motives for keeping the data secret, Russia’s Gazprom has chosen to infer that Turkmen gas reserves are not as great as had been claimed. In November 2005, Gazprom announced that it was scaling back plans to export Central Asian gas to Europe until Turkmenistan provided confirmation of its reserves.

95. Offshore Block 1 in the Turkmen sector of the Caspian Sea, explored by Malaysia’s Petronas, is to begin oil production by 2006 or early 2007. Petronas also has plans to build a natural gas pipeline, and to explore three new oil fields in the Turkmen sector. The onshore Nebit Dag block, operated by UK independent Burren Resources, has proven reserves of 100m barrels and production in 2003 of 12kbd. Dubai/Ireland-based Dragon Oil is operating the offshore Cheleken contractual area, which has proven reserves of 600m barrels and produced 11kbd in 2003. The Hazar consortium, with the participation of Mitro International, is developing the onshore East Cheleken contractual area. In 2002, Denmark’s Maersk Oil entered into an exploration and production sharing agreement for Block 11–12, covering some 5,700km² offshore.

production rapidly, reaching a level of over 200kbd (including natural gas liquids) in 2003, almost double the level reached at the end of the Soviet period. In 2004, however, oil output stagnated, and it appears to have fallen by about 5% in 2005: the authorities acknowledge a 0.8% decline officially, but the reported production figure of 9.52mt, well below the 10.1mt reported for 2004. There are serious questions about Turkmenistan's ability to sustain production over the longer term in the absence of substantial new investment. Significantly, production has held up as well as it has in recent years thanks to rapid increases in the output of Burren, Dragon and other foreign producers, rather than from the state-owned Turkmenneft.

64. The Turkmen authorities aim to raise oil production almost five-fold, to around 1mbd by 2010 and by a further 35% to 2015. Given that USGS estimates suggest that Turkmenistan's potential as an oil producer is far greater than has been recognised, the country might well be capable of achieving and sustaining such levels of production, placing it more or less on a par with Azerbaijan. However, it seems rather more likely that Turkmenistan will fail to achieve such growth, given its present approach to the governance of the sector. This represents a potentially significant opportunity foregone.

65. In addition to governance issues, access to export markets remains a deterrent to investment in Turkmenistan's oil sector.⁹⁶ Current production is roughly enough to supply the country's two refineries, and most of the resulting product is exported by rail or pipeline. However, any large-scale exploration and development effort would also necessitate the creation of substantial new export infrastructure, especially if the intention were to export crude. However, the most obviously attractive routes from a geographic or commercial perspective face serious political obstacles.

66. The growing openness of both Uzbekistan and Turkmenistan to greater foreign involvement in their respective hydrocarbon sectors reflects a welcome awareness that they will need outside investment to realise their potential. At present, both foreign policy considerations and the weaknesses of the investment environment suggest that this role will be played increasingly by Russian companies that are controlled by, or very close to, the state and by the national oil companies (NOCs) of fast-growing consumer countries like China and India, which have been seeking to expand into the CIS and the rest of the developing world.⁹⁷ NOCs may be in a position to accept lower returns on capital, because they answer to governments concerned with securing long-term oil supplies rather than to shareholders concerned with a return on their investment. They may therefore be able to outspend the international majors when bidding for licences or making acquisitions. Some private Russian companies may also be readier to invest in these republics, to the extent that they can count on strong political support from Moscow and may also find it easier to do business despite the weakness of the contracting environment. To some extent, they still enjoy an advantage over non-CIS competitors in terms of familiarity with local conditions.

67. While the greater readiness of the NOCs and Russian companies to invest may accelerate progress in developing oil resources in these two republics, they may bring less sophisticated management

96. See IEA (2005c:13–15).

97. Boxell and Morrison (2004). For a recent example, see the rivalry between China's CNPC and India's ONGP for the purchase of a relatively small CIS producer, Petrokazakhstan: the Chinese bid accepted by Petrokazakhstan in August 2005 was 21.1% above the closing price for the company's shares and implied a value of \$10.26/bbl for Petrokazakhstan's reserves – around 40% above the levels typical of emerging market oil companies and significantly above the levels of some European majors. (ONGC itself trades at around \$8.60/bbl and PetroChina (CNPC's listed affiliate) at just under \$8.10/bbl.)

to the projects.⁹⁸ Their involvement may also mean that ultimate disposal of the resources extracted will be shaped by factors other than market forces. These considerations may not seem to be of much concern given that Uzbekistan and Turkmenistan are destined to remain second-tier oil producers at best, but they take on far greater force given the evidence that the role of sovereign monopolies is growing – and will probably continue to grow – in the region’s two largest producers, Russia and Kazakhstan.

5. Recent shifts: towards Russo-Kazakh convergence?

68. Although Kazakhstan and Russia adopted very different approaches to the oil sector after 1991, both relied heavily on privatisation of oil-sector enterprises and the attraction of private capital to the sector. However, policy towards the oil industry in both states has recently been directed at expanding the state’s direct role in the ownership and management of oil-sector assets and increasing substantially the share of oil rents that it captures. The two countries still have predominantly private oil industries, and there is nothing in principle wrong with their determination to capture oil windfalls at a time of very high prices. However, the manner in which the authorities have pursued these objectives have raised questions in both cases about their commitment to competition and market reform.

Russian Federation

69. Since mid-2003, there has been a major shift in Russian policy towards the oil industry. While the legal and political onslaught against the oil company Yukos has been the most visible sign of this shift, it has not by any means been the only significant step taken. This is not the place for a detailed analysis of the Yukos affair. However, there is little doubt that the destruction of Yukos and the restructuring of the sector that has been set in train by that company’s demise will have a number of implications for the future of the Russian oil industry.

- To the extent that at least one of the apparent aims of the campaign was, from the outset, to engineer a change in ownership, the case increased uncertainty about the security of property rights and thus created further disincentives to long-term investment.⁹⁹ The case highlighted larger institutional weaknesses that are deep-rooted and affect even companies that face no risk of expropriation: the rule of law is still weak, and the scope for arbitrary official behaviour is large. There has been a general weakening of trust between business and the state, which the authorities have only lately begun taking steps to repair.
- State ownership in the sector is set to expand significantly as a result of the expropriation of Yukos assets and related developments. Yukos’s largest production unit, Yuganskneftegaz, was acquired by the state-owned Rosneft in a highly controversial auction at the end of 2004, and the major state-owned companies in the sector (Rosneft and Gazprom) have shown an interest in other Yukos assets as well. At the same time, Gazprom has bought Sibneft, whose 2003 merger with Yukos unravelled as the case against the latter escalated. Altogether, this implies a significant shift of oil sector assets from more to less efficient owners.

98. It has also been suggested that they will bring less sophisticated technologies, but this probably matters less, given the opportunities for purchasing both hardware and oil services ‘off the shelf’ from companies like Halliburton and Schlumberger.

99. Some senior officials continue to insist that the affair was simply a tax case. However, it is difficult to understand the state’s pursuit of Yukos in such terms. Often, the authorities took steps that reduced the budget’s potential gains from the case, and other aggressive tax ‘optimisers’ in the sector were treated relatively well by the authorities.

- Greater state ownership of oil producing assets is likely to distort to some degree the incentives facing the remaining private companies. Russia's private oil companies fiercely resisted the creation of a state-owned 'national oil company' in the 1990s, fearing that they would not be treated fairly by the state if they were competing with a major state-owned producer.¹⁰⁰ Now they find themselves faced with two. Even if the state should prove to be scrupulously fair in dealing with state and private companies – which cannot be taken for granted – the *expectation* that the state may not be even-handed will affect the private companies' behaviour.

70. In any case, the Yukos affair must be seen alongside other trends in state policy. The first, as noted, is the on-going campaign by the state to tighten its grip on 'strategic' industrial sectors – especially, but not only, the oil and gas sector. While Yukos was the only company targeted for destruction, other companies also came under pressure from the authorities, particularly over the threat of possible back tax claims.¹⁰¹ Threats to licences were also voiced by the authorities. In 2005, the Ministry of Natural Resources initiated a comprehensive review of licence compliance, which has fuelled further uncertainty. The principal basis for the ministry's complaints against the oil companies has been their failure to develop the reserves to which they hold licences. This is not unreasonable in itself, since the government does not wish to see companies sitting on their reserves and doing nothing to develop them. However, threatening to withdraw licences in order to spur development is hardly a solution, not least because it fails to address the fiscal and regulatory disincentives to develop those fields. Moreover, the review process is potentially very arbitrary and corruption-prone: finding violations is never difficult if officials wish to find them, given the very detailed character of the licences and the fact that key parameters (including maximum production levels) are sometimes based on technologies employed in the 1980s. Foreign investors were not exempt from this trend towards greater assertion of state power. The future prospects of TNK-BP were thrown into question by official statements concerning the need to restrict investment in 'strategic' mineral deposits to majority Russian-owned entities. Further east, the international consortium exploring the Sakhalin-3 block found itself fighting to defend its rights after the government commission on PSAs cancelled the results of the 1993 tender under which the consortium had won the right to explore and develop the block.¹⁰² The government indicated that it would open another round of bidding for the block.

71. Closely related to this is the state-owned Gazprom's drive into numerous other sectors, some of them rather remote from its core business. Gazprom's expansion in all directions risks making what is already an unwieldy and inefficient corporate leviathan even less efficient.¹⁰³ It is potentially of particular significance to the oil sector, given Gazprom's role as the state's 'coordinator' for natural gas projects in Eastern Siberia. It is not entirely clear how far this role is meant to extend, but since the main East Siberian fields involve both oil and gas, it is likely that Gazprom will have a decisive role in oil, as well as gas, developments there. For TNK-BP, this role rapidly acquired considerable meaning, as it gave Gazprom a

100. This was, of course, a self-serving argument, since the newly privatised companies also wanted to buy the remaining state-owned oil assets that would have gone into a state-owned 'national champion'. However, the argument was probably well founded as well as self-interested: there is evidence in many sectors that state-owned companies competing with privately owned rivals enjoy a privileged status.

101. This phenomenon was by no means limited to the oil sector. During the first three quarters of 2004, the State Tax Service collected three times as much in taxes for past years as in the whole of 2003.

102. The PSA itself had never been agreed, but ExxonMobil had spent some \$80m on the project. When it became clear in late 2003 that the block would not be included by the Duma in the list of those eligible for development under a PSA, the company indicated that it was prepared to proceed under the ordinary licensing regime. By then, however, a decade has passed since the original tender, and the expiry of this period provided the government with a basis on which to annul it.

103. See Ahrend and Thompson (2004).

de facto veto over the development of the Kovykta oil and gas field in Eastern Siberia, the licence for which is held by Rusia Petroleum, which is majority-owned by TNK-BP. Gazprom has not hesitated to use its leverage over Kovykta to press for a stake in the project and to use Kovykta in its bargaining with BP over other issues. As IEA (2005a) observes, the fact that any major project in Eastern Siberia will be subject to the possibly arbitrary decisions of a state-owned monopolist constitutes a significant disincentive to private investment in oil and gas extraction in that region. Potential investors will be watching Gazprom's treatment of TNK-BP closely and drawing conclusions based on the gas giant's behaviour. *Gazprom's role in this sphere is clearly problematic. At the very least, the nature and limits of that role need to be defined more clearly. Care must be taken to ensure that the monopolist cannot exploit this role for commercial gain at the expense of other companies.*

72. The third major trend is towards substantially higher taxes on oil producers. On its own, this is not a problem: as noted above, the sector has until recently enjoyed a rather lighter effective tax burden than most. OECD (2004) argues that increasing direct taxation of the natural resource sector (not only the oil sector), while reducing general levels of taxation, could help to mitigate 'Dutch disease' pressures.¹⁰⁴ Moreover, a large part of the increased taxation of the oil sector simply reflects recent price rises – the state captures a larger share of oil revenues at higher prices. However, the recent tax hikes have reduced investor returns in the sector even as state actions have already brought about a marked deterioration in the investment environment. Moreover, recent increases in the formal tax burden on the oil industry have been compounded by a more general toughening of tax administration and a marked increase in the propensity of the tax inspectorate to reopen accounts for past years, a process that has created tremendous uncertainty among investors in many sectors. The government has begun taking steps to address the problem of arbitrary behaviour by the tax inspectorate, which afflicts not only the oil sector but most of Russian business. However, progress on the reform of tax administration has been slow and the state's actions have sometimes been contradictory, with government proposals for better protection of taxpayers' rights being issued at the same time as measures providing for still tougher enforcement.

73. This is not to deny that there have been some significant improvements in oil-sector taxation. While nothing has yet been done to address the basic distortions created by the NDPI's profit-insensitivity, oil-sector taxation has been recalibrated so as to make it much more sensitive to fluctuations in world oil prices. Vasil'eva and Gurvich (2005) estimate that the oil sector's total tax burden at a Urals price of \$15/bbl (Urals) was roughly 11.2% of value added *lower* in 2005 than in 2000, while it was up by almost 19% of value added at prices of \$35/bbl or higher (Fig. 9).¹⁰⁵ This is a significant advance, but it stops far short of remedying the fundamental flaws in the tax system described above. If Russia is to maintain – let alone increase – oil production beyond the end of the decade, *it will be vital to ensure that fiscal and regulatory policies encourage the development of new oil fields to replace production from those currently in decline. That would imply, inter alia, shifting the taxation of the oil industry away from its focus on volume to a more profit-centered system.*¹⁰⁶ The authorities remain committed to such a change and the adoption of a 'differentiated' NDPI remains on the agenda. At present, the government plans to introduce discounted NDPI rates for fields in decline in 2007, as well as tax holidays for new fields in Eastern Siberia.¹⁰⁷ Given the technical difficulties involved – which concern both tax administration and

104. In fact, oil and, to a lesser extent, gas have been singled out as targets for higher taxation. Vasil'eva and Gurvich (2005) find that since 2000, the timber and metals sectors have experienced a *reduction* in their effective tax burden (which was below average *ex ante*) and that they now have the *lowest* effective tax burden of any major industrial sectors (well below that of any branch of manufacturing).

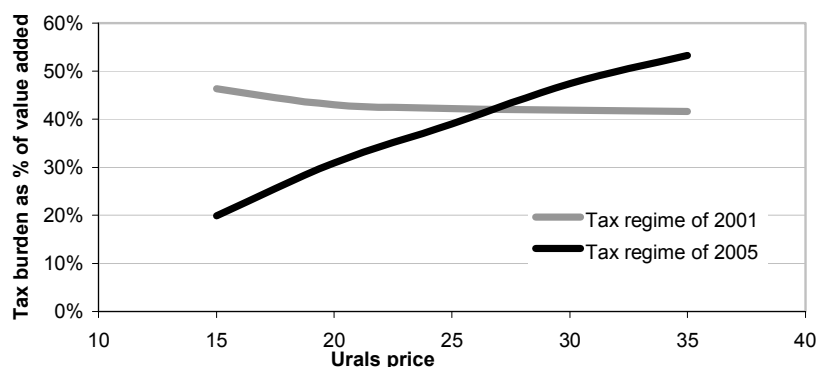
105. At \$20/bbl, it was virtually unchanged, at around 31% of value added.

106. See IEA (2002a:81–3) and (2004:304).

107. *Vedomosti*, 14 February 2006. See Annex 2 for more detail.

accounting issues, on the one hand, and the nature of oil extraction on the other – a truly sophisticated system will take some time to evolve. A more elaborate differentiation of the NDPI will have to wait, not least because the government is only now preparing to re-estimate the reserves of all existing fields under a new methodology that should provide a better basis for differentiation. *Making the entire tax system really profit-sensitive will also require tackling the problem of still-pervasive transfer pricing in the sector* (Annex 4). Thus, the authorities have opted for relatively simple (even simplistic) changes in the short term, like tax holidays for projects in difficult regions.

Figure 9. The tax burden on the oil industry at different prices



Source : Economic Expert Group, OECD calculations

74. The effect of unsettled property rights and mounting tax pressure on the sector since mid-2003 has been compounded by a tightening of infrastructure constraints on exports. Both oil companies and independent observers tend to give the state pipeline monopoly, Transneft, relatively good marks for its maintenance of the trunk pipeline network,¹⁰⁸ and during 1999–2004 it managed to increase total export capacity fairly rapidly, even if it did not keep up with the rate of growth of exports.¹⁰⁹ Transneft nevertheless came in for sharp criticism from oil producers, largely because its chosen routes often appeared to be determined by non-commercial considerations. There was too much export capacity to Western Europe and too little elsewhere, a fact that oil producers argued was contributing to the widening price gap between Brent and Urals crude.¹¹⁰ Yet the state forbade the oil companies themselves from building the export pipelines they wished to see built – even when the companies’ proposals provided for the state to own, and Transneft to operate, the new lines. While Transneft has continued to expand capacity incrementally, the authorities’ failure to take decisive action with respect to the creation of significant new evacuation routes has constrained the growth of exports. Given very high oil prices, Russian producers might simply have opted for alternative means of exporting oil, such as rail and river transport. They have at times shown great ingenuity when it comes to getting around transport bottlenecks. However, higher marginal tax rates on exports greatly reduced the attractiveness of such a solution, particularly for

108. See the assessment in Landes, *et al.* (2004b).

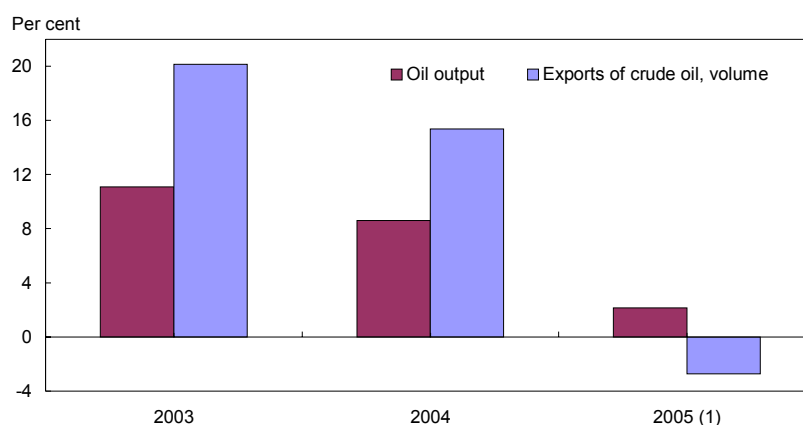
109. Non-pipeline exports (chiefly via rail and river transport) grew rapidly as companies sought to cope with export infrastructure constraints. For favourable comment on Transneft’s management and maintenance of the system, see Landes *et al.* (2004a) and Gorst (2004).

110. It is by no means clear that this was such an important factor: the spreads between Brent and Dubai (which goes to East Asia) also widened. In general, refining bottlenecks meant that the premia paid for higher-quality crudes tended to increase globally.

producers with relatively high production costs. Thus rail exports, which had grown rapidly since 2000, began to decline in April 2004 and dropped off sharply after the August 2004 hike in export duties.

75. Taken together then, three factors – the Yukos case, tax and export infrastructure brought about a marked slowdown in the growth of oil output and exports (Fig. 10). None on its own would probably have been sufficient to bring about such a sharp slowdown so quickly and so soon. To be sure, it was always clear that there were limits to the kind of fast, relatively easy growth Russia had enjoyed on the basis of existing fields after 1998 – the oil companies could not go on indefinitely harvesting the ‘low-hanging fruit’ left over from the Soviet period. Once this potential was exhausted, the fate of the sector would depend on whether or not sufficient investment in new fields had taken place. However, while these geological constraints were beginning to assert themselves in some regions, there was good reason to believe that the pattern of growth seen in 1999–2003 could continue at relatively healthy, if declining, rates until at least 2007–08.¹¹¹ Indeed, in May 2003, just before the Yukos case began, a TNK analysis of Russian oil companies’ production plans suggested that output would exceed 10mbd as early as 2007 and would rise above 11mbd in 2010.¹¹² Policy, not geology, was responsible for the sudden growth slowdown.

Figure 10. **Russian oil extraction and crude oil exports**
Growth, year-on-year



1. Jan-Nov 2005 relative to Jan-Nov 2004 for crude oil exports
Source: Russian Federal Service for State Statistics.

76. The assault on Yukos appears to have been the most important of the three factors, at least in the short term. The Yukos case triggered a sharp slowdown in upstream capital expenditure by Russian oil companies.¹¹³ Since most oil-sector investment in Russia is aimed at increasing current production rather than developing new fields, any slowdown in the growth of capital spending is soon reflected in slower growth of production and exports. A look at upstream capital expenditure by company (Fig. 11a) makes all too clear what happened: the two companies that had been recording the fastest output growth in the sector simply stopped investing. Yukos was largely *unable* to invest owing to asset freezes and other actions by

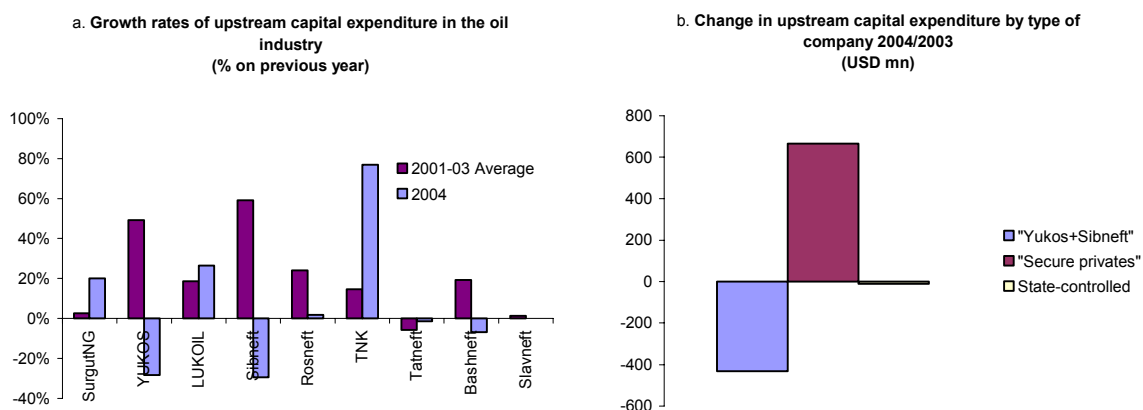
111. OECD (2004:57–8); Yergin (2006); and Collison *et al.* (2004). IEA (2005b) argues that resource depletion in mature producing regions should not yet be driving a slowdown in production, though it is a definite medium-term concern, and sees the potential for a 400–500kbd increase in exports with infrastructure already available in 2005.

112. TNK cited in Khartukov and Starostina (2005:48), table 3.

113. The aggregate increase in upstream capital expenditure in 2004 was largely the product of rising commitments to the two offshore Sakhalin PSA projects led by the international oil majors. It also reflected exchange-rate developments: the dollar value of capital expenditure rose as a result of rouble appreciation.

the state, while Sibneft's fate was thrown into question by the collapse of the merger with Yukos. Sibneft's principals, uncertain about the company's fate but still keen to sell it to someone, were more interested in taking money out of the company than investing. State-owned companies' investment more or less stagnated, while those private companies that had reason to be fairly confident of their property rights – Lukoil, Surgutneftegaz and TNK-BP – all stepped up investment (Fig. 11b). That the Yukos case (including its impact on Sibneft) was the major reason for the slowdown is also suggested by the production data for January–August 2005: while total crude oil output was up just 3.0% year-on-year, output ex-Yukos, -Yuganskneftegaz and -Sibneft was up a respectable 6.9%.¹¹⁴

Figure 11. Upstream capital expenditure in the Russian oil sector



Source : Ministry of Energy, InfoTEK, Renaissance Capital estimates, RIANTEC, OECD calculations.

77. In essence, the Russian authorities during 2003–04 lowered investors' returns (tax hikes), while imposing higher transport costs (infrastructure constraints really began to bite) and increased risk (Yukos). The state also brought about a sharp fall in the production of the single largest producer. The ensuing slowdown was thus hardly surprising. There are already some indications that the government has taken this lesson on board and is adjusting course somewhat. Reform of oil-sector taxation is once again high on the agenda, and there is a clear recognition that some differentiation of the NDPI is essential – even the Ministry of Finance now accepts this – as well as possibly some lowering of the marginal tax rate on exports.¹¹⁵ There have also been steps to provide greater reassurance to business about the danger of past privatisations being reopened and to curtail the scope for arbitrariness in tax administration. The government is working on a subsoil law that aims to begin the transition from the current licensing regime to a system based on civil law agreements. However, despite fulsome expressions of official intent, actual progress in making good on these promises has so far been limited, particularly with respect to tax administration. The draft subsoil law, in particular, falls far short of providing a framework that would be likely to deliver the kind of security and stability of conditions which are among its principal stated aims. This is particularly a concern in view of the growing share of Russia's remaining reserves that are reckoned to be difficult to recover (Annex 1). Stability of conditions matters far more when looking at marginal fields where there is less room for error in the project economics.

78. In all probability, the oil-sector slowdown of 2004–05 can be overcome – production began recovering in the middle of 2005. The Yukos affair has cost Russia in terms of time and growth, but its impact on the sector's future potential should not be exaggerated – as the continued growth of output by

114. See Aton (2005) for details.

115. See Annex 2 for details.

those companies not caught up in the Yukos affair would seem to suggest. Of far greater concern are those recent shifts in policy that probably will *not* be reversed. These point to the emergence of a new model of governance in the industry. First, the state's role in the sector is likely to increase further.¹¹⁶ In 2003, state-controlled companies accounted for about 16.0% of crude production. On the assumption that just *half* of Yukos's remaining production assets end up in state ownership, this figure will approach 40%. If the state acquires ownership of *all* Yukos's major production units (which it may well do), then around 43% of all oil production will be in the state sector.¹¹⁷ This is, of course, a far lower level of state ownership than is found in many oil-producing countries. However, given the poor performance of most Russian state companies (both within and outside the hydrocarbons sector) with respect to cost control, productivity, corporate governance and innovation, the transfer of more than a quarter of total oil production back into state ownership is unlikely to make the sector more dynamic or efficient.

79. The new dispensation may, ironically enough, create new opportunities for selected foreign companies.¹¹⁸ Prospects for foreign involvement in the sector, which have always been limited, have been further clouded since 2004 by numerous statements concerning the need to restrict foreign investment in certain sectors and, in particular, to ensure that 'strategic' mineral deposits are developed by majority Russian-owned entities. This is hardly surprising: such restrictions are to be found the world over, and they already exist in Russia *de facto* if not *de jure*. Yet restricting foreign investment in minerals sectors need not preclude significant foreign involvement. Russia's state-owned companies appear interested in attracting foreign partners to join them in major projects, and at least some in government view foreign partners as one way of mitigating the well known inefficiencies of some of the major state companies. Indeed, clarification of the restrictions on foreign access in the law on the subsoil and the new law on trunk pipelines could actually be a *positive* step from a foreign investment perspective, provided that the restrictions were not too severe and that the new legislation were clear and stable. *Other things being equal, clearly defined and consistently applied formal limits on foreign participation would certainly be preferable to ill defined and arbitrarily applied informal ones.*

80. That said, there is no guarantee that clarity and consistency will be the outcome of the present revision of subsoil legislation. It remains to be seen exactly what formal restrictions on non-residents' investment will in fact be adopted and, indeed, how 'non-resident' entities will be identified. More worrying, however, is the evidence of continuing pressure from within the state administration for the new legislation to leave the authorities considerable discretion to decide on foreign participation in the development of 'strategic' fields on a case by case basis. This would merely formalise the current informal arrangements, whereby foreign acquisition of significant stakes in Russian energy companies is virtually impossible without the informal approval of the authorities.¹¹⁹ In Russian conditions, such a case by case approach would probably not be applied in a transparent and consistent manner. In any case, it is likely that foreign companies will be confined to secondary roles for the foreseeable future. The subsoil is, of course, state property, and the Russian government is hardly unusual in wishing to favour domestic companies when developing subsoil resources. However, a protectionist approach is unlikely to be economically

116. While a stake in Rosneft may yet be privatised, there is little doubt that it will remain predominantly state-owned for the foreseeable future.

117. These comparisons are based on 2003 production data; obviously, differences in the rate of production growth in 2004–05 have altered somewhat the relative shares of different companies in total output.

118. Dienes (2004:336); Gaddy (2004:350).

119. Cf. the contrasting treatment of ConocoPhillips, which was allowed to purchase a significant stake in Lukoil, with the experiences of ExxonMobil and Total, which have both been unable to make significant acquisitions.

efficient, especially in a situation of increasing state ownership. Restricting access to auctions and tenders may also tend to facilitate corruption.

81. Despite having taken over direct control of a much larger share of production, the state remains determined to keep a tight grip on the export infrastructure. The problem here is not so much the preservation of a public monopoly on the existing system of trunk pipelines – there are good arguments why, given the nature of the inherited infrastructure, such a monopoly makes sense – but the categorical rejection of privately owned trunk pipelines¹²⁰ and the way in which decisions about the development of the public network are made. While it is probably desirable that the common network be operated by a company that is not itself engaged in oil production and export – and thus does not face the conflict of interest that such a combination of activities would imply – Transneft faces other conflicts of interest. Its monopoly on the design and construction of pipelines arguably gives it an incentive to favour longer, costlier lines. Thus, Transneft's initial cost estimates for the proposed Far Eastern pipeline were several times higher than any previous pipeline it had built – and, indeed, were well above the cost per kilometre of the Alaskan pipeline. This suggests that the pipeline monopolist was succumbing to the temptation of many regulated monopolists – to 'gold plate the rate base'. Transneft has no obvious economic incentive to opt for the most efficient export routes, and many of its decisions appear to reflect political considerations rather than commercial sense. Transneft's record strongly suggests that, in order to ensure that the most commercially efficient solutions are identified and pursued, *the authorities should reconsider their opposition to privately financed, owned and managed pipelines.*¹²¹

82. The debate over the proposed Far Eastern pipeline exemplifies many of the problems with the current arrangements for managing the oil export infrastructure. There is no denying the need to diversify Russia's export options, and, in the long run, the country will probably want to develop a major export route to the Pacific. However, the pipeline project at present appears set to go ahead before the oil that will flow through it has been found. Filling up such a pipeline without diverting large volumes of West Siberian production (possibly at considerable expense) will require the development of substantial production in Krasnoyarsk Krai, Yakutia and elsewhere. Yet no licences for most of these regions have even been scheduled for auction, and IEA (2005b) notes that exploration activity in Eastern Siberia is still only a small fraction of what would appear to be necessary. Although Yukos, prior to the assault on it, was very interested in a Chinese pipeline (the company's moves in this direction probably added to the authorities' irritation with it), the Pacific pipeline does not appear to be an urgent priority for any major Russian oil company. By contrast, there is widespread support among the companies for a pipeline to Murmansk – a deep-water, ice-free port capable of handling very large crude carriers (VLCCs). Yet Transneft continues to resist a pipeline to Murmansk, and it appears likely that, if a northern pipeline is built at all, it will run to the much smaller port of Indiga, which is neither ice-free nor capable of handling VLCCs.

83. It is important to emphasise, however, that the critical issue is *not* the relative merits of alternative pipelines. The real issue is the *decision-making process*. Questions of regional development and geopolitics appear at times to trump economic considerations and strategic decisions are subject to enormous delays. Both the northern and Far Eastern pipeline projects have been debated for some years now, without any final resolution. Certainly, the Far East pipeline is set to go ahead, but the route is still being debated and it is an open question how soon and in what volumes Russian crude will reach the Pacific. At present, a pipeline is to be built from Taishet to Skovorodino, on the Chinese border. According

120. The Caspian Pipeline Consortium's line to Novorossiisk is the sole exception. Other private pipelines are operated in Russia but these are not trunk pipelines; they are local lines that connect producing fields to the Transneft network or to export terminals. However, even these are not unproblematic, since Russian law has yet to define clearly what is and is not a 'trunk' pipeline.

121. See IEA (2002a:79).

to Transneft, it could be supplying up to 600kbd to China as early as the end of 2008. Thereafter, the pipeline will be expanded to allow the delivery of a further 1mbd to the Pacific. However, Transneft has indicated that the extension of the pipeline will finally be decided only when the government has a clearer sense of Eastern Siberia's production potential. This must raise questions about the Pacific project, since the Ministry of Industry and Energy has estimated potential East Siberian production at 540kbd by 2015 (though Minister Viktor Khristenko has spoken of as much as 1mbd).

84. Overall, the developments of the last two years have not been encouraging. Renewed insecurity of property rights is likely to shorten private investors' time horizons at a time when there is a growing need for increased exploration and investment in long-term, greenfield projects. At the same time, greater direct state control over assets in the sector is likely to lead to less efficiency, more rent-seeking and slower growth in the very sector that had been driving growth hitherto. It is also likely to lead to further confusion and delays. One of the chief problems of greater state intervention in the sector has been the authorities' inability to outline and pursue a coherent strategy towards it. All major areas of policy, from taxation to licensing to infrastructure provision, have been subject to frequent changes in stated policies, often contradictory official statements, and long delays in the adoption and implementation of major decisions. Often this is because the authorities are trying to pursue too many conflicting goals. Once taken, major policy decisions are often thrown into question almost immediately by official declarations concerning the need for further change. This means that any investment planning takes place in an environment characterised by high levels of uncertainty, much of it generated by the state. As a result, the investment decisions of both private companies and public entities are subject to delay, raising the risk that investment will not be sufficient to sustain – let alone increase – production over the medium-to-long term.

85. The foregoing suggests that PSAs in Russia may yet have more of a future than has been recognised in recent years. As noted above, the government in 2003, having supported PSAs more or less actively for over a decade, decided that they would be employed in a very limited range of cases, if at all. However, ensuring that new greenfield developments in the sector go ahead in a timely fashion in the absence of any resort to PSAs will now be more difficult than ever, since the authorities still lack any credible alternative mechanism for offering investors stable conditions over very long periods of time. This is especially true of developments offshore and in new or particularly difficult oil-producing regions, where the up-front investments in equipment and infrastructure are likely to be greater.

86. In fact, there have been some indications that PSAs may yet return to prominence, even if reform of oil-sector taxation moves forward. In early 2005, the Ministry of Natural Resources (MPR) began mooting proposals for the use of PSAs to develop offshore hydrocarbon deposits. These included reducing the number of stages in the process for concluding a PSA from 28 to four, with the aim of making it possible to negotiate PSA contracts in under half a year (many negotiations under the old legislation went on for years at a time without result). The MPR indicated that such projects would require the participation of a state company, but this role could now be filled by Rosneft or Gazprom. Rosneft has in any case supported PSAs in the past, precisely because of its potential role representing the state's interest in PSA projects. In all likelihood, the rest of the industry would go along with this. Russian oil companies are unlikely to challenge state policy too openly at present and, in any case, many Russian oil producers have long accepted that large new developments offshore and in the far north might require PSAs.¹²² The MPR's renewed interest in PSAs is therefore a welcome development. *The Russian authorities should resume work on the completion of a legislative framework for PSAs involving Russian and/or foreign companies*

122. Much opposition to the concept in the past was motivated primarily by a desire to avoid, or at least limit, the use of PSAs in Western Siberia and other mature regions (such as Kharyaga). Companies did not want to see their rivals operating in the same conditions and relying on essentially the same infrastructure but subject to different tax regimes.

that is clear, stable and streamlined. Among the most important measures will be steps to simplify the procedures for negotiating PSAs and to bring other Russian legislation into line with the PSA law.

87. If the PSA concept is not to be revived to some extent, then sorting out the taxes-and-royalties system (including such related issues as transfer pricing rules) will be all the more important – as will credible steps to curb possible *ex post* exploitation of investors by the authorities. *Further steps to reform oil sector taxation must be counted among the most important reforms needed to enhance the sector's future prospects.* The shift to a more profit-centred tax system will take some time to complete and will probably need to take place in stages, determined in part by the speed with which the authorities are able to tackle such issues as transfer pricing and the re-estimation of oil reserves. A sudden shift to a far more complex process of calculation and collection is neither desirable nor likely. However, since frequent changes to the tax system create uncertainty for investors, it might make sense for the government to devise and commit itself to a realistic tax-reform path. Specifying the kind of tax framework towards which the government was working and the stages envisaged along the way would enable companies to plan for the future.

Kazakhstan

88. Since the late 1990s, there has been a growing trend towards greater state involvement in, and direct control over, hydrocarbon developments. This has led to increasing tension with foreign investors in the country and, at times, has raised questions about the Kazakh authorities' commitment to property rights and contract stability. To be sure, Kazakhstan was never a particularly easy place to do business. As noted above, the early stages of transition were difficult, and investors have long complained about the arbitrary official behaviour, red tape and corruption that they encounter, particularly when dealing with regional authorities. However, there is a widespread perception that the attitude of the authorities has grown tougher in recent years. Even many Kazakh officials privately acknowledge this. They insist that the state allowed investors to take advantage of it in the early post-independence period and that it is now merely reasserting its legitimate interests and trying to enforce rules and conflict provisions that it had previously been too weak or inexperienced to uphold.¹²³

89. The shift in the authorities' stance vis-à-vis the industry has found expression in both formal and informal ways. Much of the conflict has centred on the interpretation of the major contracts concluded between investors and the state – both PSAs and the Tengiz contract. Since the contracts themselves remain secret, it is difficult for outsiders to judge the merits of any given dispute, but there is little doubt about the overall trend towards interpreting contested provisions in favour of the state. There have been several disputes over VAT issues, including both the state's application of *ex post* changes in VAT regulations and differences between the state and the companies about the extent of coverage of the VAT exemptions provided under certain contracts, such as Kashagan. More generally, investors and many other observers argue that tax administration has become both tougher and more arbitrary. At times, tax and regulatory issues have been used to pressure companies already in conflict with the authorities – thus, the government in 2003 attempted to impose four years of backdated VAT on field operations at Kashagan, apparently in response to the consortium's refusal to allow two Chinese companies each to acquire small stakes in the venture.

90. The most prominent conflict during 2002–03 concerned ChevronTexaco's management of the Tengiz project. Officially, the main issue concerned the switch to an accelerated depreciation schedule and

123. Calls to revise long-standing contracts were sometimes justified with reference to allegations of corruption on the part of western advisors involved in negotiating the original deals; see Pomfret (2005); and Olcott (2002).

the financing of the investment programme for the next stage of the project, intended to raise output from 285kbd to 430–500kbd. The matter was settled after a dispute that lasted for over a year. Under the agreement, ChevronTexaco agreed to forgo receipts of \$200m per year over three years – receipts to which the company insisted it was entitled under its contract, to compensate it for expenditures incurred in developing the next stage of the project. However, while the Kazakh authorities agreed to hand over this \$600m at the end of the three years, ChevronTexaco was effectively compelled to pay a substantial advance on its royalties, and there have been hints that the authorities might revise the agreement again before the end of the three-year period.

91. Canadian-based PetroKazakhstan, which was bought out by China's CNPC in 2005, found itself in a series of long-running conflicts with the authorities in connection with its development of the Kumkol field. For a considerable period, the company had to resist sustained Kazakh efforts to take control of the company. In late 2003, an Astana court issued a decision to confiscate \$6.4m after the company allegedly increased wholesale charges for oils and lubricants. PetroKazakhstan also found itself in frequent conflict with the authorities over the authorities' application of environmental regulations – which the company and many other observers insisted was arbitrary – and, at times, even over export access. The environmental issue has become increasingly controversial, and not only for PetroKazakhstan: in April 2005, the authorities instituted a ban on the flaring of associated gas. While in part a response to the conflict with PetroKazakhstan, the ban affected all producers, many of whom argue that it is not technically feasible to comply at present. The ban has been widely blamed for a sharp slowdown in production growth this year: crude oil production rose just 4.3% in 2005 on the preliminary data, after rising 16.5% in 2004.

92. At Kashagan, conflicts arose over the question of whether the field could be developed according to the original schedule. The complexity of the field is such that the Western participants decided relatively early on in the project that they wished to defer production, which will now not start until 2008. The Kazakh authorities were not pleased with this delay, which the consortium argued was dictated in part by Kazakh local content requirements and other regulations, and the authorities indicated that they might want to redraft the contract if the schedule were not met. Even after the two sides reached agreement on the delay in late 2003,¹²⁴ leading politicians continued to state that the government would demand that the original contractual obligations be revised.¹²⁵ Some executives fear another 'renegotiation' in the coming years, once Agip has built the infrastructure for the project.

93. Concerns about the Kazakh authorities' commitment to the sanctity and stability of contracts were further aroused by the government's pursuit of a stake in the 7–9bn barrel Kashagan offshore project. In 2003, UK-based BG agreed to sell its 16.7% stake in the field. Under the contract governing the project, the other members of the consortium had right of first refusal to the stake, which they wished to exercise. However, the government wished to secure the stake for Kazmunaigaz. When the investors proved unwilling to sell the stake to the state company, Kazakhstan simply adopted a law giving the state the right of first refusal over stakes in existing projects, asserting that this right, once enshrined in statute, trumped the terms of the contract itself. In the end, the two sides reached a compromise under which the Republic settled for half the BG stake, with the investors buying up the other half.¹²⁶ The conflict marked an

124. The fine for the delay was reportedly around 150 million dollars.

125. President Nursultan Nazarbayev himself spoke on several occasions of the possible renegotiation of terms for the North Caspian PSA (*i.e.* Kashagan), arguing that Western companies had taken advantage of Kazakhstan in the early years after independence.

126. It is worth noting that BG originally agreed to sell the stake to China's CNOOC and China Petrochemical Group, but neither the consortium partners nor the authorities in Astana wished to bring the Chinese into the project.

important turning point. Although there had been numerous disputes concerning the application of various contract provisions, this was the first time the authorities had openly violated the principle that contract provisions were protected from subsequent changes in national legislation.

94. Also unsettling for some investors was the apparent inability of many Kazakh officials to understand the depth of the consortium's objections. Given that, from the start, the government was prepared to pay the price BG had initially agreed for the stake, officials argued that there was no hint of expropriation involved. However, for the private players, the issue was not price but the sanctity of contract. Their primary concern seems to have been the readiness of the authorities to adopt legislation that overrode key contract provisions. This did affect the security and integrity of their property rights, even if nothing like an uncompensated nationalisation took place. After all, the value of a company's stake in such a project depends, *inter alia*, on its liquidity, which will be affected by the imposition of restrictions on its ability to realise the stake, and on any potential buyer's confidence that the contract terms are secure. Moreover, at least some of the international companies definitely did not welcome the inclusion of a state company in an otherwise private consortium, since a state-owned company's objectives are likely to be less focused on profit than those of a private one. Even Kazmunaigaz executives acknowledge that their job is often to serve state interests rather than to maximise profit. Doubts have also been expressed about Kazmunaigaz's ability to meet its share of the project costs.¹²⁷

95. The Kashagan row now appears to have been an indicator of things to come: in October 2005, Kazakhstan adopted legislation stipulating that the transfer of rights and obligation under a contract on subsoil use or the transfer of a stake in the legal entity which has such a contract can be made only with the written sanction of the state if one contractor leaves and another takes its place. The measure grants the state pre-emptive rights to stakes in legal entities possessing the right to subsoil use.¹²⁸ The amendments also provide for the authorities to make decisions concerning the transfer of subsoil use rights on fairly wide-ranging – and ill-defined – 'national security' grounds. The bill was passed very rapidly following CNPC's acquisition of PetroKazakhstan, leading to suggestions that the authorities in Kazakhstan were concerned about further Chinese acquisitions in the sector.

96. Friction notwithstanding, the authorities have largely honoured the contracts concluded with investors in the first post-Soviet decade. Indeed, after a period in which senior officials frequently mooted the possibility of significant contract revisions, the Kazakh authorities have recently stated very explicitly that existing contracts would *not* be renegotiated.¹²⁹ However, legislative changes have brought about a marked change in the conditions under which new projects can be launched. Perhaps the most visible sign of the new approach lies in the legal requirement, introduced in 2002, that Kazmunaigaz be given a 50% stake in all new projects.¹³⁰ This does not mean that all projects must be executed on a parity basis, as the

127. The law does not in fact require Kazmunaigaz to retain any or all of its stakes in such projects; it could simply sell its shares if it is unable or unwilling to finance its participation.

128. The state's pre-emptive rights even extend to the purchase of a stake in a legal entity which is in a position to influence, directly or indirectly, the decisions of a subsoil use company.

129. See, e.g. ITIC (2005b:3)

130. The legal status of this requirement is at least open to question, as the relevant decree states that a tender winner must form a consortium or joint venture with Kazmunaigaz in order to conclude a petroleum operations contract. However, other legislation, including the Petroleum and Subsoil Laws, require that such a contract be concluded directly with the winner of a tender, and not with any other person or entity. (See Decree of the Government of the Republic of Kazakhstan No. 708 (29 June 2002), 'On Approval of Regulations for Representing the State Interest by the National Company in Service Contracts for Petroleum Operations through a Mandatory Share'.)

law does not prohibit Kazmunaigaz from selling part or all of this stake. Nevertheless, the national company has the right to nominate the operating company¹³¹ even if its share in the project is far below the 50% minimum.

97. Other recent changes to legislation include much more extensive local staff requirements for new contracts and corresponding local content requirements with respect to the purchase of goods and services. The law requires investors to deal with local service providers and to purchase local equipment, goods and raw materials so long as these meet the requirements for participation in government tenders and do not exceed the cost of foreign analogues by more than 20%, a provision that, where competition within Kazakhstan is weak, offers local producers a clear incentive to raise prices. Under the 2002 decree, a government commission is to approve all tender documents and participate in tender committees in order to ensure compliance with these requirements. To date, these requirements have not been consistently enforced, however, and there are doubts about their compatibility with both WTO membership and some bilateral investment treaties to which Kazakhstan is a party. Perhaps most significant of all, new projects no longer enjoy the degree of protection for contract stability that has been available hitherto: the 2003 law 'On investments' states explicitly that contracts signed after its entry into force are subject to changes in legislation and obligations under international treaties that 'change the procedure and conditions for the import, manufacture and sale of goods subject to excise duties.'

98. Some of the most dramatic changes have taken place in the field of taxation (Box 3), although it should be stressed that these apply exclusively to new projects. Investors taking over a field from another company may inherit the tax regime under which the field was being developed, so the changes will only affect the country's ability to attract investment into new projects. When the new tax regime was introduced in 2004, critics argued that it would effectively freeze new developments in Kazakhstan, and there were some observers who argued that this was indeed the government's aim. There is no doubt about the Kazakh authorities' determination to capture a larger share of oil rents, but it is significant the tax changes were adopted against the backdrop of growing concern about the possibly damaging impact of overly rapid development of the oil sector on the rest of the economy. While oil consumers might want Kazakhstan to press ahead with oil developments as rapidly as possible, there are indeed reasonable grounds for concern about the implications of too much oil-sector growth for macroeconomic management – specifically, the threat of 'Dutch disease' and the prospect of overheating. In mid-2005, Minister for the Economy and Budget Planning Kairat Kelimbetov publicly acknowledged that the 2004 tax changes were indeed linked in part to a desire on the part of his ministry and the Ministry of Finance to delay tenders for the development of the remaining blocks of the North Caspian. He indicated that this desire reflected macroeconomic concerns rather than any belief that an optimal depletion strategy would involve leaving more oil in the ground for future generations. However, Kelimbetov also acknowledged that the regime needed to be softened, as the changes constituted a particular deterrent to the development of small and medium projects that the authorities would want to see moving forward.¹³²

99. 100. Modifications to the new regime were introduced in 2005, including the abolition of royalty for PSAs (a change mitigated by the minimum share provisions), the adoption of a 'model PSA' that allows for the possibility of lower state shares during both the investment recovery stage and afterwards, and the resurrection of a sort of 'R-factor' mechanism for assessing cumulative profitability on an undiscounted basis. Together with changes to royalty, this brought some improvement for investors, though Anderson (2004:70) estimates that these changes raise the investor's IRR by around one percentage point. The changes nevertheless appear to have been enough to satisfy some investors: while the major

131. It thus appears that Kazmunaigaz has the power to demand this role for itself.

132. ITIC (2005a:4) and ITIC (2005b:3).

western oil companies remained sharply critical of the revised regime, Lukoil in early 2005 agreed to join Kazmunaigaz in developing the Khvalynskoye field in the North Caspian, which holds an estimated 322bcm of natural gas and 53mt of oil and gas condensate. The tax take under the new regime is still heavier than that found in most other oil-producing states, including many with much lower lifting and evacuation costs.¹³³

101. While the last years have undoubtedly seen growing friction between the Kazakh authorities and the major oil companies, the situation should not be over-dramatised. Kazakhstan has not witnessed anything like the large-scale assault on property rights mounted against Yukos in Russia. The fact that the major private investors are foreign companies would in any case constitute a significant deterrent to any such attack on private property. With the exception of the state's exercise of pre-emption rights to the BG Kashagan stake, the authorities have so far resisted the temptation to revise unilaterally the contracts concluded with investors – though they have sometimes pushed questions of contract interpretation as far as they could. The much tougher tax and regulatory regime created in recent years will undoubtedly slow the development of new projects in Kazakhstan, but, given the trajectories of projects like Tengiz and Kashagan, and the sums already committed by investors, Kazakhstan is still well placed to deliver continued strong growth in oil production over the years ahead.

Box 3. The new Kazakh tax framework

In January 2004, fundamental changes to both model 1 (EPT) and model 2 (PSA) taxation regimes entered into force. The new legislation provides for identical production-sharing formulae for all new PSAs – a measure the authorities argued would increase transparency, predictability and equity, while reducing the scope for bureaucratic discretion (and hence for corruption) in the negotiation process. However, it also reduces the scope for taking account of fields' size, position and other conditions when negotiating contracts. Effectively, the investor's share is determined by the least of three possible formulae. In any case, the total state share under the 2004 legislation could not fall below 20% prior to investment return and 60% after payback was achieved.

Under model 2, the old internal rate of return (IRR) model, which was broadly consistent with international norms, has been replaced by a model that some observers believe is unique to Kazakhstan,¹ under which the tax is determined annually rather than cumulatively and is dependent on the ratio of income to expenses in the reporting year. The January 2004 amendments also removed the provision whereby EPT contracts were protected from subsequent changes to Kazakh legislation (a change consistent with the 2003 investment law mentioned above). The stability provisions continue to apply to older EPT contracts, but those operating under contracts concluded after January 2004 will face taxes and other mandatory payments calculated on the basis of the legislation in effect on the date the liabilities arise.

Even disregarding proposals that investors should carry the state company, Kazmunaigaz, for a 50% participation in any future project, the new tax regime, at \$25/bbl, could easily cut the investor's internal rate of return by 50% or more from the level achieved under the old regime – in the case of some offshore projects, it would fall below 5%, and even for on-shore developments, it would be around 7–8%.² Moreover, the new regime does not allow much increase in the investor's IRR as oil prices rise.

1. Anderson (2004:68).

2. For details, see Anderson (2004:68–71).

102. Nevertheless, it is by no means certain that the country will triple output by 2015 as planned, chiefly because of possible export capacity constraints. As noted above, the projects that are currently being planned are unlikely to deliver sufficient export capacity in the next decade. In particular, there is

133. Anderson (2004).

unlikely to be sufficient capacity to handle incremental production from Tengiz and Kashagan. One potential solution – an export terminal on the Caspian providing access to the BTC pipeline in Azerbaijan – has found favour with both investors and the government. However, progress is being delayed as a result of disagreement between investors and the government concerning the location of the facility and control over it. Specifically, Kazmunaigaz has objected to the site proposed by the investors, which would put the facility beyond the state company's control, and has proposed an alternative site in its place. If this issue is not resolved in a timely fashion, transport constraints could start to impinge on production growth later on.

Russia and Kazakhstan compared

103. While the parallels between developments in Russia and Kazakhstan should not be exaggerated, they appear to represent something more than a coincidence. In many ways, the developments described above echo the history of the oil industry in other parts of the world. Until the 1960s, a handful of international oil companies dominated the market, and oil-producing states had little option but to accept a substantial degree of foreign ownership and control over their reserves. Over time, however, local elites' bargaining power increased. This resulted from a combination of learning within the state administration and the emergence of competitors to the international majors who were willing to cede more revenue and greater managerial control to host governments in order to capture market share from their larger rivals. They also profited from the rise of western oil services companies, which provided yet another way to access the kind of technology and expertise that the majors provided. In these circumstances, developing countries were able to conclude more favourable contracts with foreign investors, and in many cases, to nationalise their respective oil sectors outright.¹³⁴ The capital-intensive nature of oil extraction also helped, since it imposed high barriers to exit when the state began to revise the bargain.¹³⁵ Initially, states' need to attract large-scale investment gave the oil companies tremendous leverage over taxation, regulatory policies and questions of institutional design. However, once investments were made, and costs were sunk, it was relatively easy for states to revise the terms of their interaction with investors.

104. One can identify similar patterns in Russia and Kazakhstan. In both instances, political leaders believe – not without reason – that the state's weak bargaining position in the very uncertain environment of the early 1990s led it to make concessions to investors (whether foreign or domestic) that it would not otherwise have made. These concessions have become ever less palatable as oil prices have risen.¹³⁶ The question of how oil rents are to be allocated has grown more, not less, acute as those rents have grown. At the same time, the strengthening of the two states' extractive and coercive capacities has made it easier for them to become much more assertive towards the oil companies. In the case of Kazakhstan, the accumulation of local experience in the oil industry has probably also contributed to a tougher stance vis-à-vis foreign investors. As in the developing world in the 1960s and 1970s, the problem of sunk costs clearly affects the bargaining power of the parties – in Kazakhstan, especially, the authorities are counting on the reluctance of companies already heavily committed in the country to exit. Some western oil executives in Almaty acknowledge that this calculation has so far proved correct: while there have been numerous

134. This is a clear example of the 'obsolescing bargain model' developed by Vernon (1971). See also Jones Luong (2004:6); Moran (1974); and Tugwell (1975).

135. Eden *et al.* (2004:6) argue that bargains between states and multinationals in manufacturing sectors are far less likely to obsolesce, not least because their investments tend to be smaller, more mobile and more closely tied to knowledge-based, firm-specific advantages.

136. Ironically, the obsolescing bargain model anticipates that the host government's perception of the cost-benefit ratio offered by the relationship with the foreign investor will be more likely to deteriorate if the investment turns out to be much more profitable than anticipated – oil booms are thus highly likely to cause oil-sector investment bargains to come under strain.

complaints about the authorities' behaviour, none of the major players has opted to withdraw.¹³⁷ Finally, if the majors were undercut in the late 20th century by emerging competition from smaller rivals and oil services companies, Russia and Kazakhstan now stand to benefit also from the increased activism of NOCs from large, rapidly growing consumer countries, most notably India and China.

105. In Kazakhstan, at least, there are also external factors that contribute to an increasingly politicised, interventionist approach to oil policy. Faced with increasing demand for its energy supplies, Kazakhstan's multi-vectored foreign policy has come under pressure. Increasingly, major transactions are being analysed to determine whether or not they mark a shift towards alignment with one country or another. Competition among US, Russian and Chinese companies, in particular, could complicate policy-making in Astana in the years ahead by giving geopolitical concerns even greater weight than hitherto. The political and legal manoeuvring that accompanied CNPC's purchase of PetroKazakhstan is likely to be a harbinger of things to come. While a compromise was reached between Astana and Beijing,¹³⁸ there remains considerable anxiety in both Kazakhstan itself and in Russia about China's long-term ambitions.

106. As a number of observers have pointed out, the expansion of the state's role in the hydrocarbons sector is hardly a novel phenomenon. On the contrary, it would not be difficult to argue that Russia and Kazakhstan are merely moving somewhat closer to the international norm in the oil business. Most of the world's major oil exporters have oil industries dominated by the state. The extent to which the private sector has dominated oil production in Kazakhstan and Russia since the early 1990s was undoubtedly highly anomalous. However, it appears to have been a *positive* anomaly, at least in terms of investment, efficiency and growth, and the two countries stand to lose much by moving towards something more akin to the international 'norm'. In both countries, the shift towards a very 'hands-on' approach, relying on direct control over assets and intervention in markets, is likely to contribute to poorer performance. The problem is not simply that re-nationalised assets are likely to be managed less efficiently. It is also that greater state ownership and intervention in the sector is likely to distort the incentives facing private companies.

107. Subsoil resources in both Russia and Kazakhstan belong to the state, and it is certainly not difficult to understand the two states' desire to exercise their ownership rights more effectively than in the 1990s. Nor is it difficult to understand why Russia, in particular, increasingly sees control over its hydrocarbon wealth as a source of geopolitical leverage. This, too, is a relatively common behaviour among oil producers. Moreover, the economic costs imposed by the new approach may not be fully appreciated by policy-makers, since the cost of this shift towards greater *dirigisme* are largely an *opportunity* cost – welfare losses arise from investment that does not take place and wealth that is not created. Since opportunity costs are 'invisible', they are often insufficient to deter the pursuit of economically inefficient policies.

108. In the case of Russia, policy towards the oil industry forms part of a broader trend towards greater state control over 'strategic' sectors, a trend that must be seen against the backdrop of the state's hitherto abysmal record as an owner of industrial assets. Even the government's own assessment of the state's management of industrial enterprises is strongly negative, highlighting not only poor growth performance but also a lack of accountability and transparency, which, in turn, feeds rent-seeking and

137. This may be one reason why there has been no parallel toughening of the state's position in Azerbaijan: investors *have* been exiting – albeit because they have failed to find sufficient recoverable reserves rather than because of mistreatment at the hands of the authorities. Azerbaijan's bargaining position now looks somewhat weaker, owing to growing scepticism about how much oil remains to be found there.

138. CNPC agreed to sell 33% of PetroKazakhstan to the state for \$1.4bn and to share its Shymkent refinery on a parity basis.

corruption.¹³⁹ The expansion of state ownership thus augurs ill for the future development of the oil industry. So, too, do the frequent changes in policy in those domains (transport, tax, etc) where the state's role is critical: in a sector where the predictability and stability of conditions are crucial to promoting investment, the Russian government has not so far proved very good at providing either for long. As noted above, the contrast between the robust growth of the oil industry and the poor performance of Russia's gas sector is instructive. Yet rather than trying to inject some of the market-driven dynamism of the oil industry into the gas sector, the authorities are currently doing just the opposite. A significant migration of assets from more to less efficient owners is now under way in the oil sector.

109. The situation in Kazakhstan is, of course, somewhat different. No significant renationalisation of oil industry assets has taken place, and the major projects now under way should be sufficient to deliver continued production growth for some time to come. Any further large projects, however, will almost certainly proceed more slowly. This appears to be what the Kazakh authorities want – as noted above, they seem inclined to slow down the further development of their hydrocarbon resources in the interests of macroeconomic management. However, it is increasingly likely that those projects which do go forward will involve Kazmunaigaz in cooperation with other state-owned companies – chiefly the NOCs of major consumer countries – or at least with companies subject to less capital discipline than the international majors. While the eagerness of the NOCs to participate in Kazakh projects may enable the authorities to get new projects under way without making big concessions to the international majors, the NOCs are likely to bring less efficient management to the projects, and their role increases the likelihood that oil-sector development will be shaped by political factors rather than market forces.¹⁴⁰

110. Underlying all of this is a basic contradiction in the actions of both Kazakh and Russian authorities. Governments in both countries have been seeking to capture a substantially larger share of oil rents, which, of itself, probably makes some sense, provided they do not overshoot the mark and discourage investment in future development. At the same time, however, the two states have taken actions that effectively increase the risks faced by investors in the oil sector and thus the rate of return those investors require in order to justify investment. In other words, investors have been asked to accept a lower rate of return in an environment of increased risk.

6. Conclusion

111. The impressive growth in CIS oil production since the mid-1990s has been overwhelmingly driven by the private sector – even in Turkmenistan, production has in recent years been sustained by fast growth among the handful of small private investors who are active there. Despite this success, there has been a marked trend in both Russia and Kazakhstan towards a greater direct role for the state in oil production. A great many factors seem to have contributed to this shift, many of them highly conjunctural and specific to one country or the other. However, a common feature has been the weakness of the administrative, regulatory and rule enforcement capacities of both states, and the authorities' frustration at their inability to tax and regulate the industry as they would like. These institutional weaknesses have not predetermined the actions taken by either government with respect to the oil industry in recent years, but they have certainly affected the state's incentives.

112. The Russian and Kazakh oil industries, like many capital-intensive extraction sectors, are dominated by a small number of large companies, with high barriers to entry and exit, and a high degree of

139. 'Materialy' (2005).

140. It has also been suggested that the NOCs will tend to use less sophisticated technologies. However, this problem should, in principle, be relatively easy to overcome, given the potential for relying on western oil service companies, which employ the most advanced technologies available.

asset specificity. Shafer (1994) argues that such sectors are likely to be both politically powerful and rather inflexible. Powerful but inflexible sectors, in turn, are likely to place exceptionally strong demands on the state, which may suffer from an erosion of its own autonomy. A relatively weak state, which finds it difficult to tax and regulate effectively, will have correspondingly greater incentives to rely on direct control rather than contract, regulation and taxation when confronting such a sector. In the case of Russia, these incentives were probably all the greater precisely because, whatever its other weaknesses, the Russian state possesses very substantial coercive capacities, capacities that are arguably out of all proportion to any of its other capabilities.

113. The irony is that if underdeveloped state capacities increase the attractions of nationalisation and/or heavy-handed state intervention, then the states most likely to opt for such behaviour will be those *least* equipped to manage industries well.¹⁴¹ The issue, then, concerns not merely the question of state vs private ownership in general but the capacity (or lack thereof) of CIS states, in particular, to manage large state-owned companies in technically complex sectors. A country where the democratic accountability of the rulers to the ruled is well established and the rule of law is relatively strong has a far better chance of ensuring that state-owned companies are reasonably well run. Where political accountability and the rule of law are weak, however, the creation of large state companies in the most lucrative sectors is likely to be associated with greater opacity, corruption and rent-seeking by insiders. Moreover, those in control of such companies will face strong incentives to resist steps to increase transparency and accountability.¹⁴² The performance of numerous large state-owned companies throughout the CIS suggests that such poor governance will contribute to higher costs, lower productivity and slower growth of output.

114. This point is extremely important in the larger debate over the so-called ‘resource curse’. A number of scholars have suggested that state ownership rather than resource wealth *per se* may lie at the root of resource exporters’ apparently chronic under-performance.¹⁴³ State ownership of resource industries may soften states’ budget constraints and encourage fiscal indiscipline, while the parastatals themselves tend to be inefficient and subject to frequent political interference. Often, they are deprived of funds they need to improve productivity.¹⁴⁴ The expansion of state ownership in major minerals sectors may thus be detrimental to overall economic performance and not merely to the performance of the sectors in question. This line of argument would be even more persuasive if, as suggested above, under-developed state capacities increased the incentives for states to nationalise.

115. The expanding role of the state in CIS hydrocarbon sectors also increases the likelihood that geopolitical concerns rather than commercial considerations will shape the industry’s development. The CIS producers would hardly be the first oil-producing states to use their resource endowments for political leverage. Nevertheless, the evidence to date suggests that the growing focus on geopolitics has led to greater uncertainty about, and inconsistency in, state policy – the Russian authorities’ difficulty in settling on a route for the Far Eastern pipeline would appear to be a case in point. This, in turn, makes investment

141. On nationalisation as a ‘coping strategy’ for weak states, see Chaudhry (1993).

142. These conclusions are unlikely to sound in any way surprising or controversial to observers of Russia’s gas monopoly or other large, state-owned oil and gas companies in the CIS.

143. See, e.g. Shafer (1994); Ross (1999); Jones Luong (2004); and Auty (2004).

144. This proposition has not undergone much empirical analysis, for the simple reason that most of the literature focuses on minerals sectors in the period from the 1960s through the 1990s – a time during which the vast majority of mineral-rich countries opted for state ownership and control of mineral reserves. There were simply not very many cases with which to contrast the performance of state-owned enterprises.

planning, by state or private companies, more difficult.¹⁴⁵ Moreover, the increasing prominence of geopolitics in oil policy creates its own problem for producing states, since they often find that deals done with one consumer country may offend others. In Kazakhstan, it must be acknowledged, the geopolitical dimension to oil policy is largely imposed on the country from without, as a result of growing competition for access to its hydrocarbon resources.

116. This pressure highlights the other side of the geopolitical coin: the major oil producers are not alone in seeing oil as a ‘strategic’ commodity that is somehow too important to be left to the market. A number of major consumers take the same view. The growing role of state-owned companies based in China, Malaysia and India – large, fast-growing consumer countries – is likely to undermine, rather than augment, the pressures for market reform in CIS oil sectors, not least because these companies are likely to be less concerned about the wider contracting environment than their private western rivals.¹⁴⁶ At present, this is most evident in Kazakhstan, where Chinese companies have been particularly active. The Asian consumer NOCs’ determination to secure oil supplies is also likely to push prices up, since this is regarded as a strategic objective by their owners, who are quite prepared to pay a premium for access to resources. The Asian NOCs are not, in any case, subject to the same sort of shareholder pressures as the western majors. They can accept lower returns on what most westerners would probably regard as relatively high-risk investments.

117. The growing role of sovereign monopolies in the sector – representing both producer and consumer interests – increases the likelihood that a growing share of CIS production will be allocated by non-market means (*e.g.* under long-term intergovernmental agreements). At the margins, this may not matter much, and the oil the consumers acquire would be oil that they would otherwise have to buy on the market. However, if enough production is tied up in this way, then the impact of supply disruptions elsewhere would be all the greater. The irony here is that consumers’ desire to lock up oil supplies is largely motivated by a concern with supply security, yet security of supply is likely to be best assured for all consumers by the existence of a more liquid global market. The collective action problem is clear: one consumer may be better off securing dedicated supplies for himself, but if too many consumers do so, then all would be worse off.

118. Developments in Russia merit separate consideration, as Russia really is the key here. The country accounts for almost 80% of CIS production at present and it accounted for about the same share of incremental CIS supply during 1998–2004. While its share of incremental output is falling and will probably continue to fall in the coming decades, it is expected to account for well over half of CIS supply even in 2025 (Fig.12).¹⁴⁷ The *étatiste* shift in policy towards the oil sector has been more pronounced in Russia than in Kazakhstan and its impact is likely to be far greater. Kazakhstan, after all, is still on course to record very large increases in production on the basis of projects already in train. While it may aggravate investors and slow some of these developments, the government is most unlikely to derail them. Kazakhstan, moreover, has legitimate macroeconomic concerns about the potential consequences of even faster growth of oil output. Russia, by contrast, has adopted a range of investor-unfriendly policies at a time when it badly needs to attract new investment to the oil sector. It faces not the potential problems of

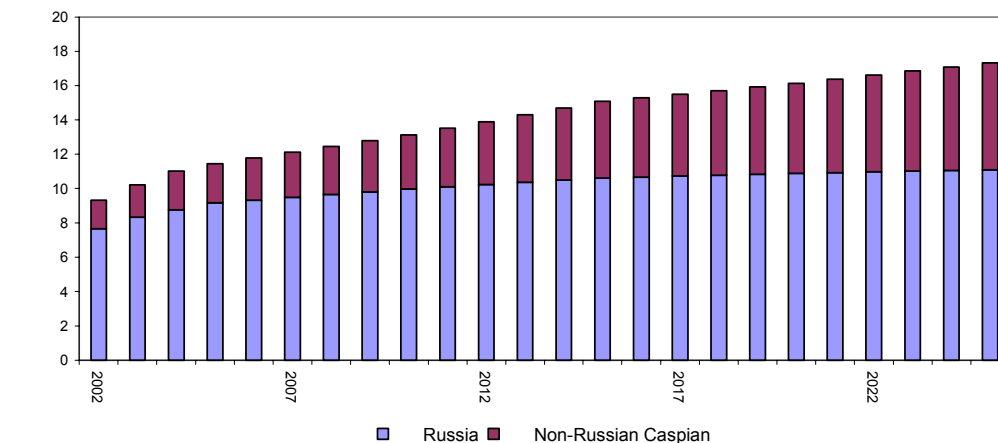
145. See the comments of TNK-BP CEO Robert Dudley at the Russian Economic Forum 2006; *Moscow Times*, 26 April 2006.

146. See Marcel (2005); Blum (2004); Boxell and Morrison (2004).

147. Based on estimates in USEIA (2005), which do not look especially bullish with respect to Russian production.

overly rapid development but the very real risk of stagnation and decline in a few years' time if investment does not rise markedly.¹⁴⁸

Figure 12. Long-term CIS oil production forecast, 2002-24, mbd



Source: USEIA (2005)

119. The foregoing should not be taken to suggest that the region's oil industries will not continue to grow. There can be little doubt that the role of CIS producers in global oil supply will continue to increase in the coming years, and even the more pessimistic assessments available point to rising net exports of crude oil from the CIS to at least 2010 or so. However, developments over the last few years mean that the growth of oil production and exports is likely to be slower than would otherwise have been possible and there are serious questions about Russian production over the longer term. Among the smaller producers, Uzbekistan and Turkmenistan are nowhere near realising their potential. While Uzbekistan's oil potential is probably limited anyway, Turkmenistan's appears to be considerable. It might well be capable of emerging as another Azerbaijan – a second-tier producer, to be sure, but a significant one nevertheless. Other things being equal, this will leave world oil supply somewhat tighter than it would be if CIS producers were closer to realising their potential. This will be good news for both OPEC and the non-CIS producers outside OPEC but it is obviously bad news for consumers.

120. There is nothing inevitable about such underperformance. There is much that Russia, in particular, can do to repair the damage done since mid-2003. This brings the discussion back to fundamental framework conditions: taxation, property rights, stability of contract, the rule of law and infrastructure development. The contrasting experiences of the CIS producers over the last 15 years suggest that investment in the oil sector in the region is highly sensitive to the state of the contracting environment and the tax system. In Russia, particularly, reform of oil-sector taxation, coupled with institutional reforms aimed at strengthening property rights and contract stability, could do much to stimulate investment in new fields, by domestic or foreign investors. The current reform of the law on the subsoil thus represents a potentially important turning point – it could do much to make matters better or worse. Russia still has a substantially private oil industry. Appropriate policies, therefore, could help it recover the dynamism it had until the upheavals of 2003–04 and, indeed, to generate greater investment in longer-term projects. Finally, *there is little doubt that a reversal of the current trend towards greater state ownership of oil-sector assets would enhance the industry's longer-term prospects.*

148. Dienes (2004) and Hill (2004) argue that Russian production will be very difficult to sustain after 2010, largely because of the policy failures of the last few years.

121. In both Russia and Kazakhstan, the drift towards tighter state control over the oil sector has largely been justified by the state's legitimate desire to capture a larger share of oil rents than it has hitherto been able to secure. As the owner of the oil in the ground, this is its right. However, it is not clear that nationalisation and heavy-handed regulation will achieve this end. The inefficiencies of state-owned monopolies in both countries, coupled with evidence of substantial tax evasion and rent-seeking by insiders in state companies, suggest that state ownership may not be sufficient to protect the state's property rights.¹⁴⁹ *State interests would be better served by an approach emphasising clear, secure property rights, a stable, profit-sensitive tax system and reliance on competition, markets and private-sector initiative.* For Russia, in particular, it is hard to exaggerate the importance of reforming oil sector taxation while creating a transparent, stable legal and regulatory framework for the sector. Given the importance of stimulating new exploration and the development of new fields in order to sustain production once the current 'brownfield renaissance' is over, this must be regarded as a matter of urgency.

122. In this context, *'secure property rights' must be understood to include those of the state itself as well as the rights of private owners.* If private capital is to provide the sector with the dynamism it needs, it will be crucial to ensure that the state has the regulatory, monitoring and extractive capacities needed to protect its own rights as the owner of subsoil resources, *without* resort to heavy-handed intervention. It must be able to devise and administer a depletion strategy that reflects its interests and to address such issues as transfer pricing in the industry. This implies that *significant strengthening of state capacities will be needed alongside any renewed commitment to private-sector development.* The question is not whether the state has a key role to play in the oil sector but whether the appropriate role will be played.

123. Ultimately, much depends on CIS producers and consumers recognising that their long-term energy interests are probably best served by reliance on the market. For CIS states, that means creating stable framework conditions for the long term, even if this sometimes requires the state to refrain from pursuing its short-term interests as aggressively as it might otherwise wish to do.¹⁵⁰ For consumers, too, the advantages of a competitive, market-oriented approach imply the need for a measure of restraint, especially when it comes to the temptation to try to lock up reserves. Transport infrastructure, in particular, should be developed on the basis of commercial rather than geopolitical considerations. There should be a strong presumption in favour of the private sector when it comes to activities that are commercial and (actually or potentially) competitive, and that do not involve sensitive regulatory or public-service functions – which is to say, most functions up- and downstream that are not directly connected with infrastructure provision. In short, both consumers and producers are best served by abandoning the widely held view that oil, as a 'strategic' commodity, is somehow 'too important to be left to the market'.

149. In Russia, for example, the Economic Expert Group estimates that tax evasion by state-controlled Gazprom in recent years has taken place on a scale comparable to that found in the oil industry; see *Rossiiskaya gazeta*, 7 December 2005.

150. This is precisely the sort of self-restraint required of Olson's (2000) 'stationary bandit'.

ANNEX 1. ESTIMATING RUSSIAN OIL RESERVES

124. Methodological differences in assessing oil reserves can have significant political and policy implications. In Russia, the state continues to rely on a Soviet-era methodology and classification system which emphasises geological substantiation of the presence of petroleum and technical recoverability, rather than economic considerations.¹⁵¹ Private Russian oil companies, by contrast, rely on western methodologies emphasising economic considerations. To complicate matters further, the two commonly used western methodologies – from the Society of Petroleum Engineers (SPE) and the US Securities and Exchange Commission (SEC) – produce different estimates. In November 2005, Natural Resources Minister Yuri Trutnev signed an order initiating the transition to a new system for classifying oil reserves, much closer to the systems used in the West. This will in due course create a much better basis for any future differentiation of the mineral resources extraction tax (Annex 2). However, the new system will not be fully operational until 2009, owing to the need to re-estimate the reserves of all existing fields under the newly approved methodology. For the moment, the state continues to rely on the old Soviet classification system.

125. Not surprisingly, given the emphasis on physical presence and technical recoverability, rather than commercial considerations, the state's reserve estimates are far larger than those derived from company data. However, the *trends* the two sets of estimates show move in opposite directions:

- From 1998 through 2004, official estimates of total ABC1 reserves fell by an estimated 2.6%.¹⁵² In early 2005, the Ministry of Natural Resources stated that reserves had increased by just 330mt (2.4bn barrels) in 2004, against output of 458mt. The ministry claims that between 1999 and 2003, reserve replacement ran at 85% of output. When they have occurred, moreover, new finds over the last decade have also tended to be smaller than previously and in fields with lower flow rates.¹⁵³ As IEA (2003:148) notes, the share of Russian reserves classed as 'difficult to recover' is already above 50% and is growing steadily.

151. For details, see IEA (2002a:71). The Russian AB classification consists of proved, developed reserves, whether they are producing or non-producing. The C1 classification is roughly equivalent to proved-undeveloped reserves but, with few economic (as opposed to geological) checks carried out. C1 thus includes an element of the 'probable' category under western classification systems. IEA (2002a) suggests that about 30% of C1 reserves would fall into the western 'proved' category.

152. Landes *et al.* (2005:33–6). Since official ABC1 reserve estimates remain a state secret, the exact numbers are unknown. However, the Russian authorities have frequently claimed that reserves are falling. The last available estimate, for 1999, was 15.35bn tonnes (ca. 112.1bn bbl). Landes *et al.* (2005) use this estimate as a starting point, together with data for crude and condensate production and official data on crude oil reserve additions (assuming 100% replacement of condensate, for which no data at all are reported), to estimate that ABC1 reserves fell 2.6% over five years.

153. The largest new field discovered in the last decade, the Upper Filanovskoe field in the Russian sector of the Caspian, has an estimated 600m barrels of oil and 35bcm of natural gas.

- By contrast, Russian oil companies reported an average 141.8% reserve-replacement ratio over the same period, increasing total reserves by just over 31% – a truly extraordinary performance by international standards.

126. There is no contradiction here: the companies' reported increases have come from higher estimates of how much of the oil at their disposal is economically recoverable, whereas the decline that so worries the authorities is the product of a failure to explore and find new sources of oil. Thus, while the authorities have been increasingly frustrated by the lack of exploration, Russian oil companies are relatively well endowed with reserves by international standards and tend not to regard new exploration as a matter of such urgency. Moreover, they have little incentive to look for new resources under current legislation.

127. Despite the variations, Russian and Western assessments are generally in rough agreement regarding the physical reserves of original oil in place. The typical Russian development plan calls for 34% recovery from the major fields in Western Siberia. Based on these plans, for every 100 barrels of original oil in place, Western hydrocarbon auditors typically ascertain only around 24 barrels of SPE category oil and as little as 18 barrels under SEC standards. The latter figure may be further reduced if the licence term is applied to the tail end of the reserves. Taking licence expiry dates into account, an average of only 11 barrels of original oil in place are currently classified as 'SEC proven'. Significant upside thus exists at those Russian fields classified as SEC proven, which could be realised with the application of technology and proactive reserve management. The recovery of these fields could reach 45 barrels per 100 barrels of oil in place.¹⁵⁴

128. A further problem with respect to reserves estimates concerns their classification. The authorities continue to regard reserves estimates as state secrets. This practice that reduces transparency and creates difficulties for investors – particularly foreign investors – who may be legally barred from access to information they need in order to pursue their projects.¹⁵⁵ Publishing official estimates of Russian reserves would increase both transparency and investor confidence, while also removing a legal impediment to the activities of foreign companies that can be used to apply pressure to them in a selective and arbitrary manner.

154. See Bush (2004) and Collison *et al.* (2004). Recovery factors well above 45% (and sometimes as high as 60%) have been realised in some mature basins, including Alaska and the North Sea, but these would still be characterised as outliers. That said, technology changes rapidly, and such high recovery factors were until recently regarded as impossible.

155. See *Vedomosti*, 24 October 2005, on the problems encountered by BP and ExxonMobil with respect to access to geological information. Maps of greater precision than 1:2500 (1cm per 25m) are also state secrets.

ANNEX 2. RUSSIAN OIL-SECTOR TAXATION

129. The taxation of the sector has been a matter of controversy throughout the post-Soviet period, with the nature of oil-sector taxation generating as much debate as the overall size of the tax burden (whether formal or actual). In principle, the tax system should aim to ensure an adequate flow of revenues to the state, as the ultimate owner of the subsoil resources, without acting as a disincentive to the economically efficient development of those resources. To that end, it is necessary to offer investors a reasonable balance of risk and return within a fiscal framework that is transparent, stable, predictable and able to provide a level playing field for all. It is far from clear that Russian oil-sector taxation meets any – let alone all – of these criteria. It has been neither stable nor particularly transparent, and it is, on the whole, oriented more towards revenues and physical production volumes than profit.

130. In addition to general taxes, such as VAT, the profit tax and the unified social tax, there are four major components of the sector-specific tax regime that applies to the Russian oil industry:

- *The mineral resource extraction tax* (NDPI), introduced in 2002, replaced the old mineral resource replacement tax, most royalties¹⁵⁶ and the crude oil excise duty. The NDPI is levied on an easily controlled base – physical volumes – at a rate linked to the average export price of Urals crude.¹⁵⁷ The NDPI was adopted largely in order to put an end to oil companies' use of transfer pricing to avoid taxation. In this, the NDPI has been a great success, but its insensitivity to field conditions and other factors affecting the actual profitability of oil production means that it can have perverse effects. When introduced, the flat NDPI rate was supposed to be a temporary measure – it was to be replaced by a rate of 16.5% of the wellhead value of crude oil from January 2005, but this has not happened nor is there any sign that it will in the foreseeable future.
- Having been scrapped for a time in the mid-1990s, the *crude oil export duty* was reintroduced when oil prices began to recover in 1999, in an effort to secure the state a larger share of the windfalls arising from higher export prices. Since 2002, it has become progressively steeper,¹⁵⁸ so that the duty now captures \$0.65 of every \$1.00 price increase above \$25/bbl. Combined with the NDPI, this means that the state collects over 90% of the marginal revenue on a barrel of oil exported at a price above \$25/bbl.¹⁵⁹ At prices of \$40/bbl and above, it captures over half of the gross export revenue via these two taxes alone (Fig. 12).

156. Royalty is now charged only on oil extracted while exploring and appraising reserves.

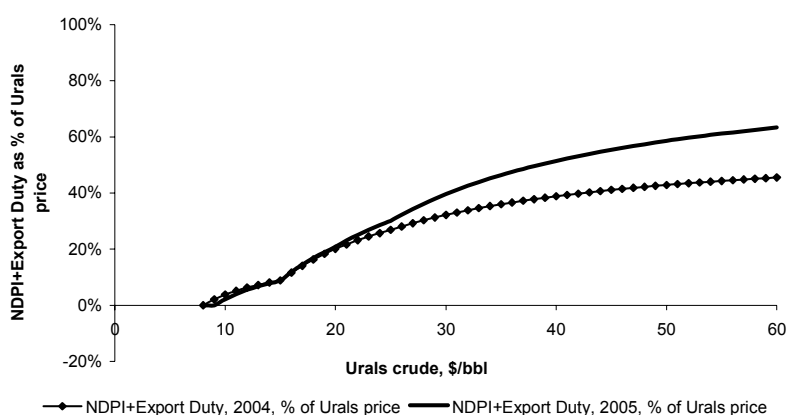
157. The formula in force since 1 January 2005 is: $Rb419/tonne \times (Urals \text{ export price} - \$9/bbl)/261 \times Rb/\$$ exchange rate.

158. The formula in force since 1 August 2004 is as follows. If the average export price of Urals crude for the preceding two months is \$15 or below, no duty applies. If it is between \$15 and \$20, the formula is: $(Urals \text{ price} - \$15) \times 0.35$. From \$20 to \$25, it is $\$1.75 + (Urals \text{ price} - \$20) \times 0.45$. Above \$25, it is $\$4.00 + (Urals \text{ price} - \$25) \times 0.65$.

159. See Tsentr razvitiya (2004) for an estimate of \$0.94 on the dollar.

- *Export duties on petroleum products* have been levied since 1999. They vary according to both price and product, and tend to be adjusted by the government frequently in an *ad hoc* fashion. Overall, this has tended to be the least stable part of the oil-sector tax regime, not least because the government has used it to pursue sometimes contradictory goals – seeking to promote product rather than crude exports, while trying to hold down domestic product prices during seasons of high demand, such as the spring sowing, the harvest, and the run-up to winter. The authorities have been moving towards adopting a stable formula for such duties, in the interests of transparency and predictability, but none has yet been formally adopted. There is also discussion of greater differentiation of duties by product quality, so as to encourage investment in better refining capacity.
- *Excise duties* are charged on gasoline, gasoil and motor oil at rates set in roubles per tonne on an annual basis. The current rates are Rb2,657–3,629/tonne for gasoline (depending on the octane level), Rb1,080/tonne for diesel and Rb2,951/tonne for motor oil.

Figure A2.1. The impact of changes in the NDPI and Export Duties, 2004/2005



Source: OECD

131. Given the difficulties the Russian authorities have faced as a result of the aggressive use of transfer pricing in the sector, the reliance on relatively profit-insensitive but easy-to-collect taxes is hardly surprising. However it gives rise to problems. The NDPI, in particular, ignores field conditions such as reservoir size and depth, well flow rates, field depletion rate, crude quality and other factors that affect the profitability of extraction.¹⁶⁰ This can deter both greenfield developments and steps to extend the life of producing fields that are in decline. While the finance ministry has tended to view proposals for a differentiated NDPI with suspicion, fearing that a more complex tax will make corruption and evasion easier, the NDPI in its current form can render uneconomic the development of mature or difficult fields that might be profitably developed under a different tax system. This is rapidly becoming a matter of some urgency: at present, over 70% of Russian oil fields now yield such low flow rates that their operation is reckoned to be only marginally commercial at historic average oil prices – over half of Russia's reserves now in development yield flow rates of 10 tonnes per day or less, compared with average rates in the Middle East of roughly 243 tonnes.¹⁶¹ IEA (2005b) notes that as many as 380,000 wells are currently idle in Russia, in large measure as a result of the tax system.

160. For details, see IEA (2002a:81–3) and Daniel and Fernando (2004).

161. IEA (2003:148).

132. A second problem with the NDPI is that, given the sometimes wide differences between Urals CIF and domestic prices,¹⁶² the actual tax rates on domestic crude sales can end up being both much higher and far more volatile than they appear. In other words, there is not necessarily a direct relationship between the returns to the state and the returns to companies. Small and/or high-cost fields may be taxed even while they make losses, while other fields may yield super-profits. Such perverse outcomes are most likely to befall producers with limited access to export channels – particularly, small producers, who often have little choice but to sell their output to the large VICs.

133. Much criticism has also been directed at the very high tax rates levied on price increments above about \$25/bbl under the revised schedule for the crude oil export duty. Such high marginal tax rates enable the state to capture a very large share of the windfall revenues generated by rising oil prices, which may make sense in terms of macroeconomic management. To the extent that the authorities resist the temptation to use such revenues to finance sharp rises in spending, taxing away oil windfalls can help sterilise the inflows generated by rising prices and thus mitigate ‘Dutch disease’ pressures and the risk of overheating.

134. However, such high marginal tax rates also make Russian supply relatively price-insensitive and will render production from some higher-cost fields unprofitable for the oil companies even if the Urals price is far above the combined costs of production and transportation. Over time, such a tax regime will discourage exploration and development, since the state’s take in higher-cost projects will be greater and investors in any significant greenfield developments will face potentially large tax payments well before capital payback. In effect, the current regime reduces the range of potentially economic fields. Ultimately, this is bad for the budget as well as the industry, since it will tend to depress both current production (marginal wells will not be worth employing) and investment in new fields (small, marginal or even large deposits may not be commercially attractive if they are not very low-cost prospects). Moreover, the willingness of investors to live with such a tax regime, which implies accepting longer payback periods, is likely to be reduced by the instability of the tax regime itself – a problem that will be difficult to address unless the authorities revise their view of PSAs.

135. The Russian authorities are not by any means unaware of the problems just outlined, and oil-sector taxation is very much on the government’s agenda. As noted above, even the finance ministry now accepts the need for a differentiated NDPI, while the Ministry of Economic Development and Trade has been putting forward proposals to reduce NDPI rates for fields that are over 80% depleted and to introduce tax holidays for new fields in Eastern Siberia and the Timan-Pechora Basin, and on the continental shelf. By far the most ambitious ideas have been put forward by a working group headed by the Federal Energy Agency (FEA) and comprised of government officials, non-governmental experts and oil company representatives. The FEA proposes as the ultimate goal of reform a differentiated tax that takes account of eight criteria: the geographical concentration of recoverable reserves (tonnes/km²), the extent of field depletion, the size of recoverable reserves, the depth of the reservoir, the location of the field, the field’s proximity to infrastructure and (for offshore projects) water depth.

136. Given the state of Russian field data and the limited capacity of the state bureaucracy to administer such a tax, such a sophisticated NDPI is unlikely to be feasible for some years yet. In the interim, it might make sense to adopt a simpler differentiation of the NDPI, which relies on a small number of variables that are easily collected and monitored. Such a system would need to be implemented in a manner that did not give much discretion to bureaucrats. In the Canadian province of Alberta, for example,

162. The domestic crude price does not always correlate closely with the export price and sometimes even moves in the opposite direction as a result of administrative measures or other developments that restrict exports, leading to gluts on the domestic market. In 2002–03, domestic crude prices fell as low as \$4–5/bbl for short periods.

the royalty system takes into account three basic variables – the age of the field, the depth of the oil and the flow rate – all of which are easy to monitor. The FEA's own preference for a phase-one NDPI reform would involve a set of discounts to the existing NDPI based on a subset of factors, including location and depletion.

137. At the end of April 2006, the government approved its initial oil-sector tax proposals for submission to the State Duma. These include:

- extension of the basic NDPI regime, due to lapse at the end of 2006, until 2016;
- a reduction of up to 70% in the NDPI for fields that are at least 80% depleted, based on ABC1 reserve estimates, for those companies that conduct production accounting separately for individual fields;
- complete NDPI holidays for new fields in Eastern Siberia until cumulative production reaches 25mt or for a maximum of 10 years from issuance of a production licence (15 in the case of a combined exploration and production licence); and
- a commitment to reduce excise taxes on low-sulphur refined products in order to stimulate production of more light-end products.

138. The government estimates that 11-12% of Russian production will be subject to NDPI discounts in 2007–09, particularly in mature producing regions along the Volga. In practice, tax holidays will probably be effective for shorter periods than the 10–15 years in the proposals: the term of the holiday will be calculated from the issuance of the licence, but commercial production under such licences will not begin for several years after they are granted. Nevertheless, the holidays look relatively generous – certainly more generous than earlier government proposals. The major surprise was the decision to limit them to Eastern Siberia, but this may change before the measures reach the statute books. Many inside and outside the government are still pressing for tax holidays for the shelf and Timan-Pechora, and the finance ministry has indicated that the government probably will return to the question of tax holidays for the shelf, at least. It is also unclear how quickly excise differentiation can be implemented. According to Deputy Finance Minister Sergei Shatalov, this must await the Ministry of Industry and Energy's adoption of European standards for oil product quality, which could take another two years. Nevertheless, the package should help to stimulate badly needed investment in new fields relatively quickly.

ANNEX 3. EXPORT INFRASTRUCTURE

139. The issue of evacuation routes constitutes a particular problem for all CIS producers, for a number of reasons, involving geography, geopolitics and the legacies of the Soviet past:

- With the exception of Russia, all are landlocked. Even Russia faces many of the problems of a landlocked producer, since most of its production is located deep inland and its existing maritime export terminals are often closed for part of the winter owing to weather conditions (ice in the north and storms in the Black Sea). This imposes additional transport costs on CIS oil producers, who already face higher extraction costs than their competitors in many other parts of the world.
- Russia's two most important maritime evacuation routes, via the Black Sea and the Baltic, both run into external bottlenecks – the Turkish Straits and the Danish Straits, respectively. While the problem of traffic via the former is well known, the latter has also recently been designated an ecologically troubled zone.
- The inherited Soviet infrastructure is overwhelmingly oriented towards exports to Western Europe. This lack of diversity of export markets has, for Russia in particular, helped to widen the price margin between Brent and Russia's poorer quality Urals export blend as Russian exports have grown.
- Non-Russian producers initially had little or no access to export markets except via Russia's pipeline network. Yet political instability in much of the Middle East and South Asia, coupled with the political obstacles to financing any evacuation routes via Iran, meant that the Caspian states' options for diversifying their export routes were limited.
- The oil transport infrastructure left over from Soviet times was in bad need of investment anyway. Much of it was old and in need of refurbishment, while rapidly changing patterns of production and consumption meant that the flow of oil through the former Soviet space changed radically, creating excess capacity in some areas and bottlenecks in others. Transneft has done better than many expected in maintaining and upgrading the system, bringing accident rates down and replacing large stretches of the network. Nevertheless, the age of the system remains a concern.¹⁶³
- Because oil exports were centralised and monopolised under the Soviet system, there was neither a direct link between producers and exports nor a commercial role for the pipeline system. The network therefore was constructed in such a way as to blend crudes, with no differentiation of qualities. Because the Russian industry has never been able to agree on a quality bank¹⁶⁴ to address this problem,

163. IEA (2002a:89) observes that the oil-field gathering lines, which are operated by oil producers rather than Transneft, represent the most vulnerable part of the oil transport system.

164. A quality bank allows producers of higher-quality crude to be paid compensation when their crude is mixed with poorer-quality oil in a pipeline. Compensation is paid at the expense of producers of lower-quality crude.

producers of higher quality crudes are penalised. Where possible, they have sought to bypass the Transneft system, but this is not usually possible and most Russian exports are still a Urals blend.¹⁶⁵

Russia

140. Given the problems cited above, Russia has hitherto done remarkably well at increasing export capacity since the late 1990s. Initially, capacity additions were not needed, because exports had fallen so sharply at the beginning of the decade that there was spare capacity in export pipelines. However, Collison *et al.* (2004) estimate that Transneft's export capacity utilisation reached 95% by 2001, making it essential to add export capacity fairly rapidly in order to sustain export growth. This the company managed to do for a number of years by relying to a great extent on de-bottlenecking, which added an estimated 27mt per annum in export capacity during 2003–04,¹⁶⁶ and on incremental additions to the network. Such a gradual approach appears to suit Transneft, as it obviates the need for large-scale external funding, which would reduce Transneft's independence. Incremental additions also enable Transneft to begin recouping its investments relatively quickly, while the oil companies benefit from a process of steady expansion rather than having to wait for long periods while major projects are completed. The major exception to this incremental approach has been the Baltic Pipeline System (BTS), which transports Russian crude to the port of Primorsk, in Leningrad Oblast. While the BTS was essentially built as a bypass, to enable Russia to export crude directly rather than paying transit fees for the use of Latvia's Ventspils terminal, it also represents a considerable addition to Russia's export capacity: initially commissioned at about 240kbd at the end of 2001, it has since been expanded to 1mbd, with plans to increase this to 1.24mbd by 2006.

141. Other projects have also been put in train to increase Russian oil exports, especially those to non-CIS destinations. The 180-km Odessa–Brody pipeline, built in 2002 to export Caspian crude to Europe via Ukraine, has been reversed to export Russian crude via the Black Sea. There have also been numerous smaller projects, including proprietary terminals.¹⁶⁷ Altogether, Transneft was able to accommodate an increase of just under 1.9mbd in deliveries to export destinations during 1999–2004.¹⁶⁸ Exports via rail, river and other routes also increased rapidly, with such bypassing infrastructure (river, rail and proprietary terminals) handling an estimated 772kbd in incremental exports during 1999–2004 (Fig. 13). A project to reverse the Adria pipeline, running from the Adriatic Coast in Croatia to the Druzhba line in Ukraine, would allow Russian crude to reach the Mediterranean. However, the Adria reversal, which has been in gestation since 2000, has stalled on account of a combination of environmental concerns and disputes over transit tariffs. The project may never be realised.¹⁶⁹

165. The need to maintain the Urals blend creates an additional inefficiency, as Transneft has to maintain far more oil in the system itself than it would otherwise do.

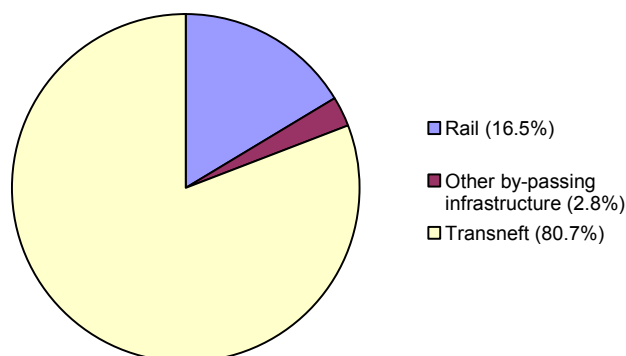
166. Landes *et al.* (2005:97).

167. For details, see Collison *et al.* (2004).

168. Roughly 88% of this was Russian crude; the balance was increased transit of Caspian crudes.

169. Croatia's request for higher transit tariffs seems to be the immediate reason for the delay in implementing the Adria project. However, the deeper underlying rationale concerns the possible environmental impact, as Croatia is heavily reliant on tourism. The rejection of the pipeline in a key environmental study in October 2005 may have dealt a final blow to this long-delayed project.

Figure A3.1. Non-CIS Russian crude oil exports, 2004, by form of transport



Source : Renaissance Capital (2005)

142. Nevertheless, infrastructure constraints have imposed increasing costs on Russian oil producers, restraining the growth of crude exports. Exports by rail rose by over 420% during 2000–04, and probably would have grown still faster had it not been for changes in the tax regime that made such exports less commercially attractive. The period also saw a 21% rise in exports via other non-Transneft channels. Depending on route and distance, non-pipeline exports can cost over \$9 per barrel more than exports via the Transneft system.¹⁷⁰ These constraints are aggravated in winter by Russia's heavy reliance on Novorossiisk, which often closes due to storms in the winter months, and Primorsk, which ices over. Indeed, one of the main criticisms of infrastructure policy in recent years has been the build-up of additional export capacity via ports that are subject to seasonal disruptions in winter and the constraints of the straits beyond. While there has been discussion of a possible pipeline bypass around the Turkish straights (the president himself mentioned it in his annual address to the Federal Assembly in 2004), little has been done and it is not clear that any such line will be built.

143. Another side effect of the export infrastructure problem is that, where rail and other by-passing infrastructure are either unavailable or unattractive, Russian companies simply end up refining more oil than they would like. This, combined with sharply higher taxes on crude exports, has contributed to faster growth in exports of refined products. Net product exports, mostly gas oil and heavy fuel oil, jumped from 1.2mbd in 2000 to an estimated 2.1mbd in 2003, of which two-thirds were transported by rail. However, the companies would probably be better off exporting crude via pipelines, for three reasons:

- Transportation costs are much higher for products than for crude, especially if the latter goes out by pipeline. Collison *et al.* (2004:20) estimate the break-even oil price for product exports to be around \$11/bbl higher than for piped crude exports. Some of this differential reflects taxes and duties, which have since changed in favour of products, but most of the difference (around \$6–7/bbl) is transport costs. Most product exports are already transported by train, barge or road-truck. This is reckoned to be more expensive than rail or other alternative transport for crude exports, but the changing structure of export duties has recently made product exports relatively more attractive.
- Russian refineries produce too little per barrel at the light end of the spectrum and too much heavy fuel oil. Increased exports of light products thus automatically leave producers with excess fuel oil on their hands, for which there is little demand.
- The problem of excess fuel oil production could be resolved via refinery upgrades. Yet such investments are unattractive precisely because domestic prices for crude and refined products are

170. See the estimates in Landes *et al.* (2004a); also Milov (2005).

highly volatile, as a result of both crude oil export constraints and sometimes heavy-handed attempts by the government to manage the domestic market via export duties and other interventions (often in an effort to hold down domestic product prices). Differentiation of the NDPI, combined with the creation of a quality bank and the adoption of a more stable, less interventionist approach to product markets and export duties on products would create greater incentives to invest in refinery upgrades.

144. The above considerations mean that the growth of both investment and production are to some degree constrained by limited export options. Lukoil has claimed that, absent export constraints, it could have increased crude output at rates 2–3 percentage points per annum faster than it actually achieved.

145. There is a growing consensus that sustaining export growth over the years to come will require more than further incremental additions. Russia needs significant new export capacity. It also needs to diversify its export routes in order to reduce somewhat the Brent-Urals gap that has widened as a result of a glut of Russian crude in Western Europe. The principal options under consideration at present involve a route to the Far East and a route to the Arctic:

- The Far Eastern pipeline now seems certain to go ahead, although the exact route is still being discussed. The proposed line is currently planned to run from Taishet, in Irkutsk Oblast', to Skovorodino, in Amur Oblast'. From there, it is to be piped east, to Perevoznaya, on the Pacific coast, with a possible spur from Skovorodino to China. Nevertheless, official statements and actions continue to leave open the question of which destination – the Pacific or China – will be the first priority.¹⁷¹ This underlines the geopolitical conundrum the project poses for Russia: both China and Japan have been pressing for their favoured routes to be given precedence. Moreover, as noted above, serious questions remain about the economics of such a route at present, and it is not even clear that Russia will be able to fill a pipeline of any size without diverting substantial quantities of crude from West Siberia.
- A number of Russian oil companies have for some time been pressing for a pipeline to Murmansk, on the Kola Peninsula. Most major producers would welcome such a pipeline, which would give Russia an oil terminal at a deep-water, ice-free port capable of accommodating VLCCs. Yet Transneft continues to resist the idea, offering a much less promising route to Indiga instead – and even that seems unlikely to advance very far until the Far Eastern pipeline is built.

146. The crucial point here is not to do with the merits of one pipeline or the other. The deeper problem lies in the policy process. It may well make sense for Russia to maintain and develop its inherited pipeline network as a vertically separated, state-owned monopoly: because Transneft is not a producer, it does not face the conflicts of interest that the vertically integrated Gazprom confronts when it comes to managing and developing the gas pipeline network. However, decisions concerning the development of new transport routes continue to be characterised by long delays and to be driven less by economic efficiency than by a mix of geopolitical considerations and Transneft's corporate interests. Transneft's monopoly on the design and construction of pipelines gives it an incentive to favour longer, more expensive routes, while its apparent desire to avoid too much reliance on external finance makes it reluctant to tackle more than one big project at a time. As a result, the first oil is likely to flow through the Far Eastern pipeline, which has been under discussion since 2001–02, no sooner than 2008, with the northern route coming on stream even later – if ever.

171. In 2004, the government opted in principle for a line to Perevoznaya, with a spur to China. This was widely seen as a victory for Japan. In April, however, the first stage of the project was approved – a 600kbd line from Taishet to Skovorodino, only 70km from the Chinese border. This prompted speculation that the Pacific segment would not be built as quickly as planned.

The Caspian producers

147. *Azerbaijan's* principal export routes since independence have included the Baku–Novorossiisk pipeline, which sends SOCAR crude to the Black Sea via Russia, and the Baku–Supsa pipeline, which mainly carries the AIOC's 'early oil' from ACG to Georgia's Black Sea coast.¹⁷² In May 2005, however, Azerbaijan began filling the Azeri section of the long-awaited 1mbd Baku–Tbilisi–Ceyhan (BTC) pipeline that runs 1,760km from the Azeri capital to the Turkish Mediterranean port of Ceyhan. At a cost of almost \$4bn, the BTC pipeline allows oil to bypass the congested Turkish straits and is also the first pipeline exporting Caspian crude that does not transit Russia.

148. The BTC's long and circuitous route to the Mediterranean betrays the geopolitical considerations that formed an important part of its rationale – while giving Azerbaijan an export route that does not transit Russia or go via the congested Turkish straits, it also avoids Iranian involvement. However, BTC is privately owned, belonging to a consortium led by BP and including a number of other international companies along with SOCAR.¹⁷³ For Azerbaijan, the desire to diversify its export routes on geopolitical grounds was reinforced by a desire to reduce reliance on the Transneft system, in which the mixing of crudes works to the detriment of producers of better-quality oil. Azerbaijan estimates that the mixing of pure 'Azeri light' into the Urals blend in the Transneft system is costing the country \$4–5/bbl. SOCAR is therefore to reduce exports via Novorossiisk in order to fill up the BTC. In due course, it may stop using Novorossiisk altogether. The AIOC, however, plans to continue to export via Supsa and Batumi on the Georgian Black Sea coast.

149. In addition to the BTC line, Iran, Russia, and Ukraine have proposed alternative and supplemental oil export routes from Azerbaijan. The European Union's Transport Corridor Europe Caucasus Asia (TRACECA) programme has been active in the Transcaucasus since 1993, upgrading and integrating rail and road transportation networks in an effort to promote trade ties with Europe along a East-West corridor. In Azerbaijan, the TRACECA program is providing logistical support to help Azerbaijan's aging rail system meet the country's growing oil transit needs.

150. *Kazakhstan* has proved to be perhaps the most commercially focused of the major CIS producers when it comes to the development of export routes – there is little indication that geopolitical considerations have played a major role in forming policies in this sphere. The authorities are simply concerned with finding ways of getting Kazakh exports to market via a variety of routes. Moreover, oil companies operating in Kazakhstan report that the Kazakh authorities do engage in real consultations with producers when considering potential pipeline projects. The great bulk of Kazakh oil exports are routed via pipeline through Russia and other neighboring countries. Kazakhstan also exports some quantities of oil by tanker to the ports of Caspian littoral states and by rail. Efforts are underway to expand the country's export infrastructure, especially to the east, to diversify export routes and keep up with rising production over the next decade.

151. Early on, transit routes were a major problem for Kazakhstan. Kazakhstan accused Russia's Transneft of such monopsonistic practices as imposing artificially high assessments for technical losses and assigning arbitrarily long routes. Russia used its transport network to pressure Kazakhstan in the dispute over ownership of the Tengiz field – the dispute was resolved, and pipeline constraints eased, after Russian equity participation was agreed. There was also evidence of discriminatory pricing: the IMF (2002) estimates that transit tariffs for Kazakh crude were typically double those of Russian crude. Kazakh

172. Oil products have been exported by rail to Georgia's Black Sea ports.

173. Given its participation in ACG, Lukoil was originally keen to take part but the Russian government's opposition to the whole concept of the pipeline meant that it ultimately declined to be involved.

producers also suffered significant losses as a result of the lack of a quality bank in the Transneft system, though it would be difficult to describe this as discriminatory against Kazakhstan, since it also imposed losses on Russian producers of better-quality crude.

152. In 1994, the country negotiated an agreement with Russia providing Kazakhstan a 3mt per year (roughly 60kbd) quota to be exported via the Atyrau–Samara pipeline, half of which was to transit Russia for export to non-FSU markets. The quota was subsequently raised to 15mt, nearly all for non-FSU destinations. In 2002, Astana and Moscow concluded a 15-year transit agreement under which Kazakhstan will export 340kbd via the Atyrau-Samara line, which has recently been upgraded. The great bulk of this oil is destined for non-CIS markets. Russia has promised to increase the capacity of the line to around 500kbd. However, while exports via Samara are expected to grow in absolute terms, the relative importance of this route is to decline as the Caspian Pipeline Consortium (see below) line is expanded and other routes are developed. Oil is also exported via the port of Aktau, which was expanded from 60 to 160kbd capacity in 2000, and barged to Makhachkala, in Russia, where it enters the Russian pipeline to Novorossiisk. Aktau's importance is likely to grow if and when substantial volumes of Kazakh crude begin flowing into the Baku-Tbilisi-Ceyhan pipeline. Kazakhstan ships additional crude to Russia via the Kenkyak–Orsk line, which runs from the Aktobe fields to the Orsk refinery in Russia, and has a capacity of 130kbd.¹⁷⁴

153. Roughly 1600km in length, the pipeline operated by the Caspian Pipeline Consortium (CPC) connects Kazakhstan's Caspian area oilfields with Novorossiisk. The governments of Russia, Kazakhstan, and Oman developed the project in cooperation with a consortium of international oil companies, which now operate the pipeline, making it the only trunk pipeline in Russia not owned and operated by Transneft.¹⁷⁵ The CPC was built as an extension of the existing infrastructure in the region, with new components of the line running from Komsomolskaya in Russia westwards to Novorossiisk. The Soviet-era lines around the Caspian which feed the CPC have been extensively refurbished. Since the first oil flowed in late 2001, the CPC had raised its throughput to around 650kbd – roughly 550kbd from Kazakhstan and a further 100kbd from Russian producers prepared to pay a premium to export higher-quality crude via the CPC rather than accept the losses arising from the blending of crudes in the Transneft system. Initial plans called for expanding the CPC to 1.5mbd by 2008, but the second phase of construction was delayed for over two years owing to disagreements within the consortium. Only in October 2005 was agreement finally reached – largely on the Russian government's terms.¹⁷⁶ The lengthy dispute over the CPC expansion was a further reminder that, despite the progress made in negotiating oil export routes in the 1990s, Kazakhstan's dependence on Russian routes remains a problem. Also significant was the Mazeikiu nafta dispute over Kazakh shipments to Lithuania in late 2005 (see above).

154. The first section of a Kazakhstan-China pipeline was completed in 2003, running from the Aktobe region to Atyrau. Construction began on the second segment of the Kazakhstan-China pipeline in late September 2004. The roughly 980-km pipeline from Atasu, in northwestern Kazakhstan, to Alatau Pass in China's Xinjiang province was completed in December 2005. A later stage of the project is to raise the pipeline's capacity from an initial 200kbd to 400kbd. In addition to the Kumkol crude which is to be pumped through the Chinese pipeline, there may be West Siberian crude delivered via the Omsk–Pavlodar

174. Some of this oil is used in swaps, as Kazakhstan supplies the Orsk refinery in Russia and processes Russian crude at its Pavlodar refinery.

175. The ownership structure of the CPC is as follows: Russian Federation 24%; Republic of Kazakhstan 19%; ChevronTexaco 15%; LukArco 12.5%; Rosneft-Shell 7.5%; ExxonMobil 7.5%; Sultanate of Oman 7%; Agip 2%; BG 2%; Kazakh Pipelines 1.75%; Oryx 1.75%.

176. *Vedomosti*, 7 October 2005; *Moscow Times*, 7 October 2005.

pipeline. Lukoil is reported to be interested in using the line. The Kazakh and Chinese national oil companies are jointly financing the project, yet the Chinese oil company will be responsible for filling the pipeline from its oilfields in Kazakhstan once it is finished. Eventually, the Kazakh–Chinese line is to run almost 3,000km from Atyrau to Alashankou, in Xinjiang. Its construction faces major difficulties, because it is being laid in seismically active areas, characterised by extreme climatic conditions (both very hot summers and very cold winters), heavy rainfalls and flooding. In addition, for all these reasons, the region also has little pre-existing industrial infrastructure.

155. The government maintains that, despite the construction of the Kazakhstan–China and BTC pipelines, Kazakhstan will still need additional export routes with a capacity of 300–400kbd by 2011. Among the options under consideration are:

- *A subsea trans-Caspian pipeline* connecting to the Baku–Tbilisi–Ceyhan (BTC) project. However, pipelines under the Caspian are unlikely to be built until the legal status of the sea has been clarified. Indeed, some observers fear that uncertainty about the legal position regarding the Caspian waters may even constrain the growth of tanker traffic – it is already cited by some Kazakh officials as one of the reasons why oil swaps with Iran, which have been conducted for some years now, remain on such a limited scale. Yet given the likelihood that Azerbaijan will not produce enough crude to keep the BTC full for any long period, it is still highly probable that, one way or another, Kazakh crude will find its way into the BTC.
- *A pipeline to the Persian Gulf* through Turkmenistan and Iran. Geographically, this is an attractive option for Kazakhstan but the difficulties of dealing with the authorities in Turkmenistan, combined with US opposition to any major project that will benefit Iran, make this an extremely tough project to finance.
- *A pipeline to the Pacific*, running through China. This is clearly a very long-term prospect and it is not clear that it will ever make commercial sense, especially given the appetite for Kazakh crude in China itself.
- *A new pipeline through Russia*. Kazakhstan's desire to diversify export routes and reduce its dependence on Russia notwithstanding, evacuation routes via the Russian Federation remain in some cases the least problematic, given the difficulties posed by disputes over the Caspian and by political factors in Iran and Turkmenistan. However, as noted above, Kazakh transit through Russia is still subject to some uncertainty, as evidenced in Transneft's refusal to guarantee Kazakh supplies to Lithuania.

ANNEX 4. TRANSFER PRICING

156. The use of transfer pricing in the oil and gas sector has been the focus of fierce and continuing controversy in both Russia and Kazakhstan. The issue has been less prominent in Azerbaijan, although the Azeri authorities have indicated that they follow developments in Kazakhstan closely. As a rule, the tax burden in the oil industry is considerably heavier upstream than downstream. This can make upstream transfer pricing particularly attractive in the sector. Inexperienced tax administrations, such as those of the CIS states, may be ill equipped to police the sometimes rather sophisticated transfer-pricing practices of large oil companies. The response of the authorities to this problem, in the case of Kazakhstan, has been the adoption of extremely aggressive transfer-pricing legislation, combined with ample discretion for tax officials. In Russia, the authorities have employed other methods, both formal and informal, to curtail transfer pricing – indeed, the determination to curb this practice accounts for some of the major peculiarities of Russian oil-sector taxation. Ultimately, some means of tackling the problem of tax avoidance via transfer pricing must be created if oil-sector taxation in the region is to be put on a sound footing. While the OECD Transfer Pricing Guidelines¹⁷⁷ provide a basis for such a solution, Engelschalk (2002) points out that their application in CIS states will require capacity building in tax administration, especially in large taxpayer departments. The tax inspectorates of CIS oil producers still do not appear to have a sufficient number of a transfer pricing experts with a good understanding of the oil business.

Russian Federation

157. The practice of transfer pricing in Russia's export-oriented resource-extraction sectors in recent years has been so pervasive as to distort in quite a fundamental way the picture of the economy that emerges in the official national accounts – a very large share of the value added generated in extraction industries actually shows up in the data as 'wholesale trade'.¹⁷⁸ While there are a number of reasons for the use of transfer pricing to reallocate financial resources within a business grouping, it is clear that tax avoidance looms large among them. The authorities are probably right to see it as the single most important reason for the use of transfer pricing.¹⁷⁹ Transfer pricing has proved an exceedingly effective tax-avoidance mechanism in situations where some *ad valorem* tax is applied to a particular stage in a production chain but does not apply to transactions further 'downstream', involving subsequent buyers and sellers. It is also widely employed to transfer income from more profitable elements of a grouping to those showing losses.

158. Russian tax legislation is nevertheless surprisingly liberal when it comes to transfer pricing. Article 40 of the Tax Code of the Russian Federation permits transfer pricing but seeks to limit its utility as a tax avoidance tool by stipulating that intra-group or intra-company prices may deviate from market prices by no more than 20%. If the deviation is greater than 20%, then the authorities are entitled to base tax

177. See OECD (1998).

178. See World Bank (2004:59–76).

179. Moser (2004) also notes that, in many cases, transfer pricing helps Russia's vertically integrated oil companies to control their sometimes rebellious and irresponsible subsidiaries. Where lower-level managers are not regarded as wholly reliable, transfer pricing can be used to keep them from controlling too much cash.

claims on market prices. Moreover, the tax service is permitted to investigate the basis for transaction prices only in specified circumstances – e.g. where there transactions are between related entities, where the prices charged by a taxpayer for the same good/service fluctuate too widely within a short period, etc.

159. The problem here for the authorities is that the legal basis for establishing relationships between entities (set out in Tax Code article 20) is limited: direct share ownership of at least 20% of one of the parties' equity, subordination of one company executive to another, family ties and a few others. Thus two wholly owned subsidiaries of a single holding company are not, under article 40 at least, related entities. Under Russian law, a court can find that entities are related on other grounds than those set out in article 20 (indeed, the absence from the tax code of any guidance to judges means that almost any grounds will do). However, this involves considerable time and cost for the authorities. It is thus relatively easy for Russian corporate groupings to create the *appearance* of arm's-length transactions even when operations are taking place among closely related entities. Provided the producer does not sell its output to final consumers at prices that are radically different to those employed in transactions with the related entity, it will be difficult for the authorities to act. In any case, most large corporate taxpayers in Russia can easily present some economic justification for internal transfer prices.

160. Hitherto, therefore, the government's efforts to combat transfer pricing have been more focused on the design of specific taxes than on the transfer-pricing provisions of the Tax Code. Thus, the design of the NDPI, in particular, reflects a determination to limit the scope for tax evasion via transfer pricing. In this, it is undoubtedly successful, but the price of that success is, as noted above, a tax system that is oriented to volume and revenue rather than profit and that creates some very distorted incentives and perverse outcomes. Since the key to tax evasion via transfer pricing is concentrating income in the least-taxed elements of a company or business grouping, the authorities have also liquidated the so-called 'internal offshore zones' previously allowed by Russian law – and exploited most aggressively in the oil sector by Sibneft and Yukos.¹⁸⁰ In the wake of the Yukos case, the authorities have also used both formal and informal means to pressure companies to reduce their reliance on offshore zones outside Russia. However, perhaps the most aggressive actions by the tax authorities have concerned their rather expansive interpretation of the concept of 'good faith' and of a 'conscientious taxpayer'. In short, schemes that are formally legal may be found to be illegal – and punishable – if the authorities conclude that a taxpayer has not been acting in good faith and that tax avoidance is the main motive for this or that transaction or pattern of transactions. In that context, any use of transfer pricing for tax purposes looks risky.¹⁸¹

161. The government is nevertheless committed, at least in principle, to reforming the Tax Code provisions governing transfer pricing. In particular, there are plans to broaden the definition of 'related parties' in the tax code but also to provide some guidance to judges as to what other grounds may serve as the basis for a finding of 'relatedness'. At present, the text of the code gives the state too little protection, while the lack of guidance to judges provides too little protection for taxpayers – the scope for arbitrariness is very great if a case reaches the courts. The Ministry of Finance also wishes to alter article 40 so as to provide better grounds for defining what is a 'market price'. The government may also shift the burden of proof when it comes to justifying the economic basis for transaction prices. At present, it is up to the tax organs to prove that prices deviate from market prices in ways that are not economically justifiable. However, there may nevertheless be good news for taxpayers. Deputy Finance Minister Sergei Shatalov has argued that the government should scrap the 20% corridor and the provision concerning fluctuations within a short period of time in favour of an assessment based on minimum and maximum prices charged

180. In that order: Sibneft's effective profit tax rate in the years prior to the eruption of the Yukos case was even lower than that of Yukos.

181. It says much about the weakness of the current version of Tax Code article 40 that it did not form the basis for any of the tax-related cases brought against Yukos.

in transactions between unrelated parties. In any case, genuine arm's-length transactions need not be defended: prices can only be called into question in transactions among related parties.

162. Opportunities and incentives for abusive transfer pricing methods could also be alleviated by the adoption of group relief (or tax consolidation) in the Tax Code. Within each vertically integrated oil company, the various subsidiaries still file separate accounts with the authorities under Russian Accounting Standards. If oil company accounts were consolidated, transfer-pricing schemes would lose much of their appeal, since the ultimate profit tax liability would depend on the consolidated results of the group.¹⁸² Most major Russian oil and gas companies already publish consolidated accounts that bring their subsidiaries into one set of figures under International Accounting Standards (IAS) and/or US Generally Accepted Accounting Principles (GAAP).

163. Whatever measures the authorities adopt, it is clear that some adequate system for dealing with transfer pricing will be crucial to any attempt to resolve the other defects of the system of oil-sector taxation.

Kazakhstan

164. In the case of Kazakhstan, the issue of transfer pricing has arisen less in conjunction with domestic transactions than in the context of cross-border transactions. In 2001, the country adopted a highly idiosyncratic transfer-pricing law (TPL), which has been sharply criticised by both domestic and foreign investors in the country. The law established the state's right to control for transfer pricing – and, if it deemed necessary, to levy taxes based on prices other than those used by the transacting parties – in a wide range of foreign-trade transactions. Unlike Russia, Kazakhstan seems not to have been concerned about domestic transfer pricing. The authorities are, however, concerned about import as well as export operations, believing that international oil companies have sometimes used inflated values for imported machinery and equipment.

165. The TPL may be used to regulate:

- transactions between mutually dependent or associated parties;
- barter deals;
- transactions settled by means of mutual offsets;
- transactions involving parties registered (residing), or having bank accounts, in designated offshore jurisdictions;¹⁸³
- transactions with legal entities that enjoy special tax concessions or privileges by law; or
- transactions with legal entities that have declared losses for two tax years preceding the year in which the transaction is concluded (the law does not specify whether or on what basis entities engaged in foreign trade are obliged to establish *ex ante* their counterparties' recent financial health).

182. Moser (2004).

183. Specifically, those jurisdictions whose legislation does not require sufficient disclosure of information to the Kazakh authorities or which provide for preferential tax treatment.

166. Some of these criteria have little obvious connection to abusive use of transfer pricing. Entirely missing from the legislation, moreover, is any reference to the ‘arm’s length’ principle, which stipulates that unrelated parties are free to agree price without falling afoul of transfer-pricing rules. The Kazakh authorities take the view that, given the difficulties they face in establishing whether or not entities are truly related, the arm’s length principle need not apply. Investor groups have gone so far as to press for the introduction into law of a version of the arm’s-length principle that places the burden of proof on the *taxpayer* – companies would be exempt from transfer pricing controls if they could *prove* that transactions involved neither related parties nor undue influence. However, the government has so far failed to act on such proposals. Transfer pricing can be deemed to take place even where there is no evidence that the parties are affiliated. It is defined purely in terms of the deviation of transaction prices by 10% or more from the price the fiscal organs deem to be the ‘objectively formed market price’. If the authorities opt to correct the transaction price, they will use the market price they have determined. This means, *inter alia*, that a transaction executed with a 9.99% deviation from the ‘market price’ will not be corrected but one that is 10.01% off the authorities’ view of the market price can be adjusted by the full 10.01%.

167. The framers of the 2001 TPL also opted for a rather restrictive range of methods to determine proper market prices. Instead, the law sets out a methodology that fails to account for all cost and quality differences. Three methods are permitted for determining the ‘market price’:

- the comparable uncontrolled price method relies on prices for identical or similar goods, services or works sold under comparable conditions to a buyer not related to the seller;
- the cost-plus method, which can be employed where conditions do not permit a comparable-price evaluation, bases the ‘economically warranted’ price on the sum of incurred costs plus a mark-up; and
- the subsequent sale price method determines the market price on the basis of the difference between the prices at which goods or services are initially sold and the resale price, albeit with account taken for confirmed costs incurred by the buyer when re-selling.

168. The provisions have attracted enormous criticism. The methods outlined are somewhat restrictive, in that they do not account in any way for special types of operations, such as tolling, forfeiting and factoring. Indeed, the law focuses entirely on the goods in question and their price, with little regard for the nature of the operations involved or the broader context in which the transaction takes place. The criteria for the use of authorised data sources in making both comparable-price and cost-plus assessments are rather vague and have been challenged by investors, while the range of ‘authorised’ sources is in any case relatively narrow. The cost-plus method does not allow for taking into account a wide range of costs arising from such things as extended storage, hedging and insurance.

169. Investors complain that the TPL’s deviation from international norms does not merely create problems for them in Kazakhstan: it also makes it harder for them to obtain relief in their home countries under treaties on the avoidance of double taxation. Accountants also argue that the TPL has become one of the ‘selective enforcement weapons of choice’ when officials wish, for whatever reason, to put pressure on a company. The TPL has thus remained a sore point between investors and the government, and there have been numerous consultations and proposals for reform since it was adopted in 2001, but to date its fundamental provisions remain unchanged.

ANNEX 5. SELECTED MAPS

Map 1. Selected oil and gas production and transport infrastructure in the CIS



Source : US Government

Map 2. Caspian region oil pipelines



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